Portland General Electric Day-Ahead Market Benefits Studies

COMPARATIVE BENEFITS FOR PGE OF JOINING EDAM VS MARKETS+

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PGE Day-Ahead Market Participation Benefits Summary

PGE's benefits from joining EDAM or Markets+ markets are primarily driven by:

- Production cost savings
  - PGE replaces internal gas generation with lower cost market purchases across cases, especially during high solar periods
  - Production cost savings tend to be higher in M+ vs EDAM, with lower sales attenuating these savings in EDAM
- Market trading revenues
  - Increased net trading revenue when PGE joins EDAM
  - Decreased net trading revenue when PGE joins Markets+ principally due to lower RT trading revenues in M+ vs WEIM

Portland General Electric System Cost by Case ($ Millions)

		BAU	WEIM Transition	Bookend EDAM	EDAM Split	Markets+ Split	Bookend Markets+
Market Membership	**Metric**	**EIM Only**	**EDAM**	**EDAM**	**EDAM**	**Markets+**	**Markets+**
Adjusted Production Cost	Cost	$332.3	$327.0	$328.7	$340.0	$319.1	$318.4
Wheeling Revenues	Revenue	$1.7	$0.1	$0.0	$0.1	$0.3	$0.3
Trading Revenues:							
Bilateral	Revenue	$2.41	$5.33	$0.79	$4.49	$3.45	$3.30
WEIM	Revenue	$15.71	$8.57	$11.31	$5.41	-	-
Mkt+ RT/WEIS	Revenue	-	-	-	-	$4.34	$4.12
EDAM	Revenue	-	$11.06	$21.66	$23.55	-	-
Markets	Revenue	-	-	-	-	$7.16	$6.48
Total System Cost		**$312.5**	**$301.9**	**$295.0**	**$306.4**	**$303.8**	**$304.1**
Benefit to BAU			**$10.6**	**$17.5**	**$6.1**	**$8.7**	**$8.3**

WECC-Wide Benefits Summary

The implementation of M+ and/or EDAM produces significant WECC-wide customer benefits, with **benefits ranging from $639-$1,051 million per year** across the scenarios considered

- A single market covering most of the WECC (bookend EDAM in this case) produces the highest benefits
- Two-market EDAM/M+ scenarios produce ~$110-120 million/year fewer benefits than the single market
- WEIM transition, with a limited EDAM footprint and no Markets+, produces the lowest benefits

WECC-Wide Benefits ($ Millions)

	BAU	WEIM Transition	Bookend EDAM	EDAM Split	Markets+ Split	Bookend Markets+
WECC-Wide						
Adjusted Production Cost	$10,313	$9,704	$9,010	$9,894	$9,956	$9,919
Wheeling Revenue	$447	$374	$129	$372	$481	$425
Trading Revenues:						
Bilateral	$1,294	$856	$483	$485	$483	$344
WEIM	$330	$307	$260	$233	$183	$99
WEIS/Mk+ RT Market	$27	$30	$31	$88	$127	$130
EDAM	-	$562	$945	$982	$681	$680
Markets+	-	$0	-	$450	$728	$954
Total System Cost	**$8,214**	**$7,575**	**$7,163**	**$7,284**	**$7,273**	**$7,287**
Benefit Compared to BAU		**$639**	**$1,051**	**$930**	**$941**	**$927**

The Bookend EDAM produces the lowest WECC-wide APC, indicating the most efficient system dispatch

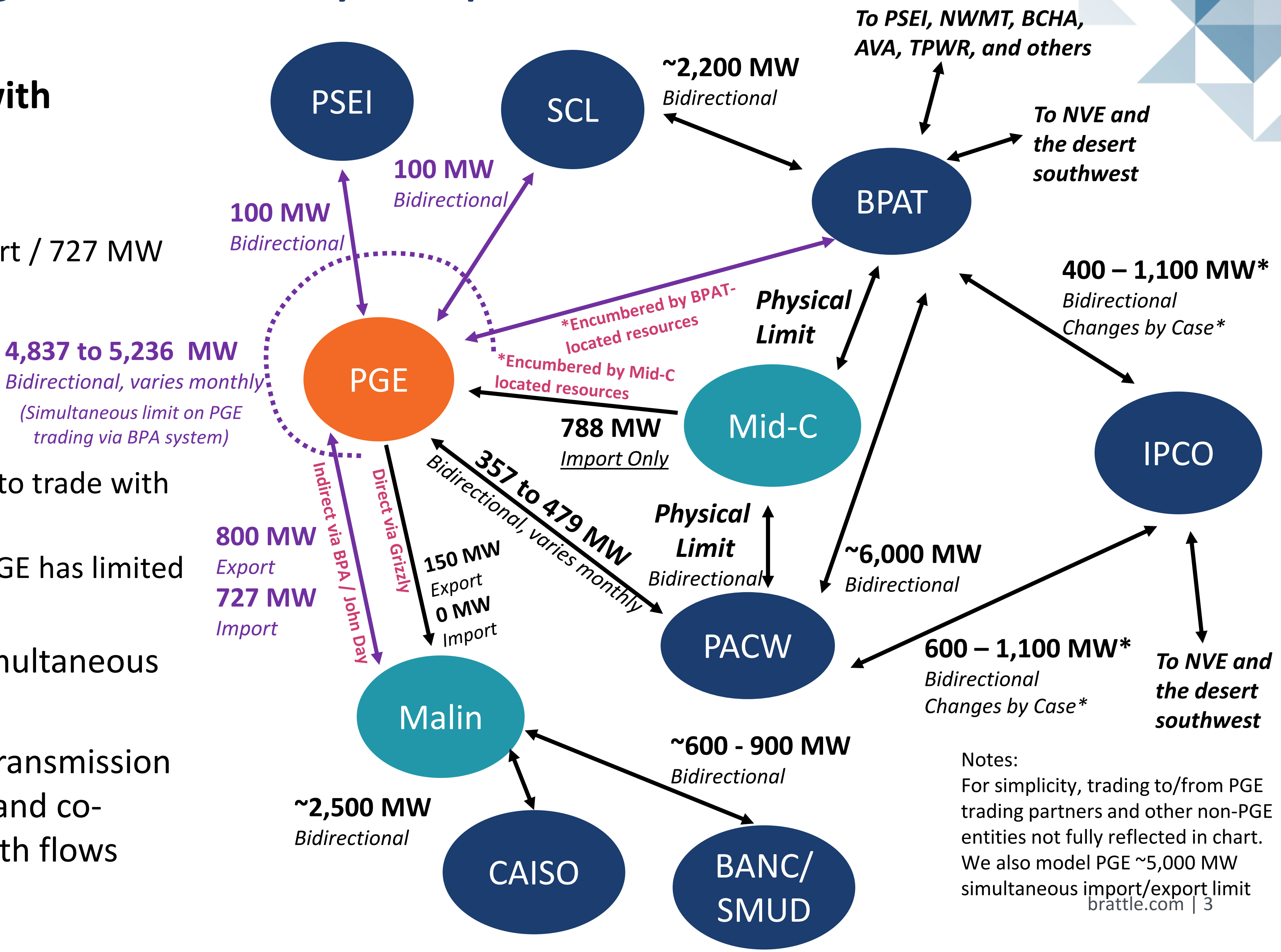
However, wheeling revenues, bilateral trading gains and market congestion may be higher in some split cases

All market participation scenarios show benefits relative to BAU

PGE Modeled Trading Connectivity Map

PGE's biggest trading paths are with California, PAC, and BPA

- **California & PAC**
  - California (via Malin): 950 MW export / 727 MW import to CAISO and BANC/SMUD
  - PAC: ~500 MW PACW
- **BPA & Mid-C**
  - BPA: over 4,800 MW of TTC
  - Mid-C: 788 MW net import for PGE to trade with other PNW entities, including PACW
  - Without IPCO & NVE in Markets+, PGE has limited access to solar in the M+ footprint
- We modeled PGE's ~5,000 MW simultaneous export/import limit
- Our model also includes physical transmission limits, such as WECC-rated paths, and co-optimizes physical and contract path flows



Notes:
For simplicity, trading to/from PGE trading partners and other non-PGE entities not fully reflected in chart. We also model PGE ~5,000 MW simultaneous import/export limit

BAU Case

BAU case assumes the day-ahead market will remain a bilateral market outside of the SPP RTO west, and that current WEIM and WEIS members remain in those markets

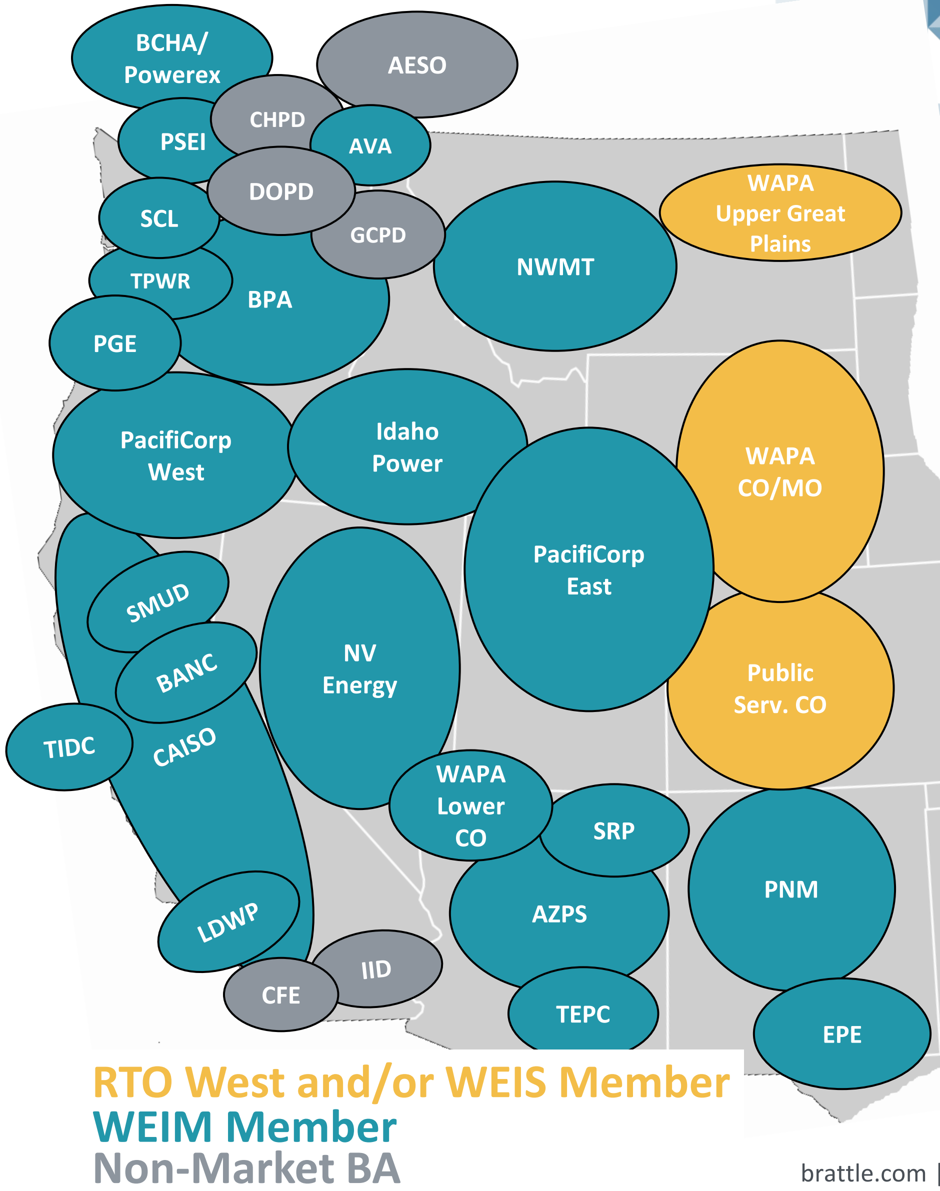
PGE trading dynamics in BAU

- California: PGE imports 3,000 GWh from California, mostly midday solar
  - *PGE also exports 800 GWh to CAISO in WEIM (direct CAISO trades reflect WEIM transfers)*
- Mid-C Trading Hub: PGE imports 3,500 GWh and exports 1,650 GWh
  - *Largest sellers to Mid-C are BCHA and BPAT hydro, largest buyers are BPAT, NWMT, PACW*
- PACW and BPAT: both 1,000 – 2,000 GWh of flows

Portland General Electric Total Trading All Types - GWh

Partner	BAU	
	Exports	Imports
BPAT	714	447
PACW	459	746
PAWA	486	27
SCL	211	22
PSEI	421	275
MidC	1,650	3,417
Malin	827	2,977
Total	**4,769**	**7,912**

BAU Market Footprints



WEIM Transition Case

WEIM Transition case assumes PGE joins EDAM with entities have announced to join EDAM and IPCO, and other entities remain as they are in the BAU case

- Entities that join EDAM assumed to remain in WEIM

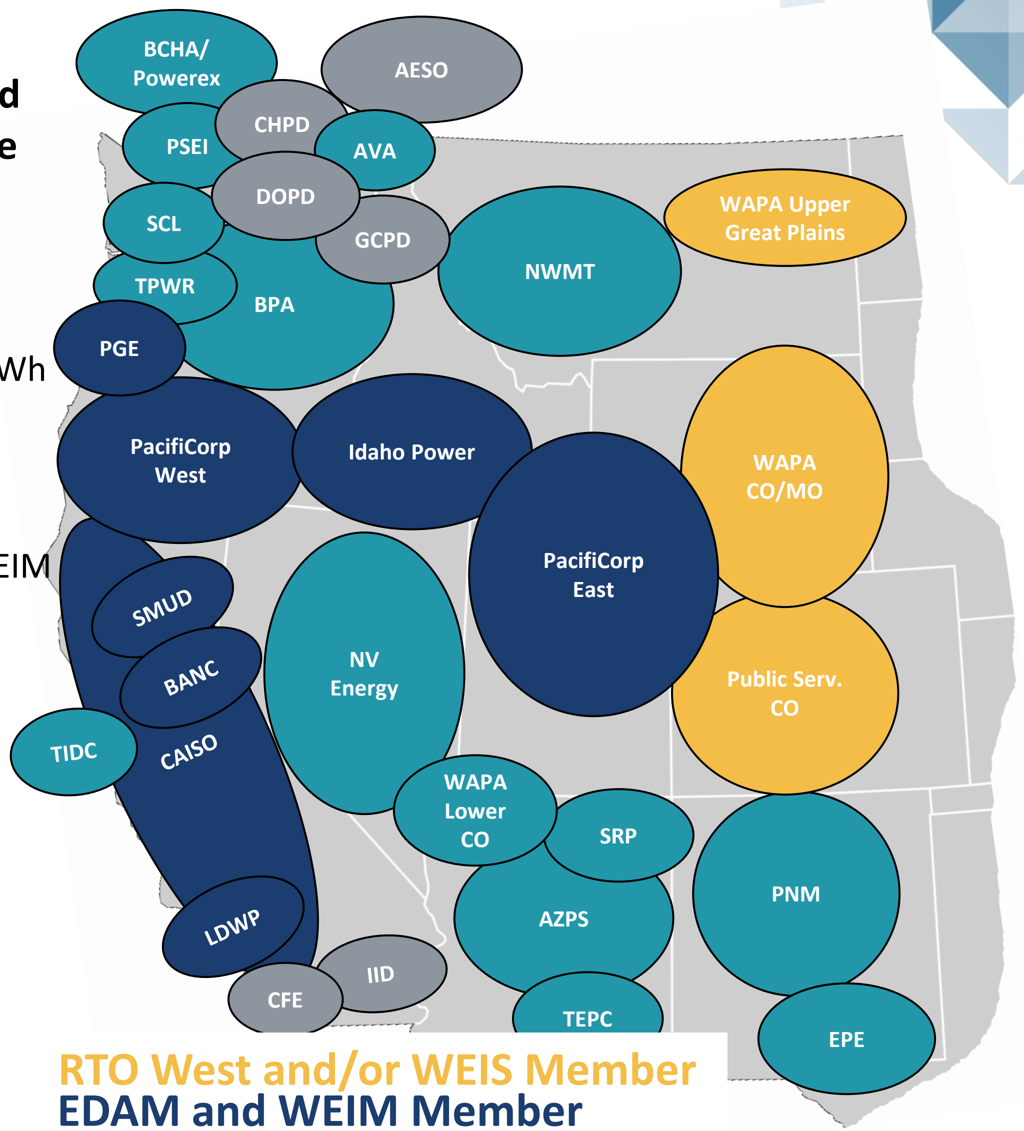
PGE trading & benefits dynamics relative to BAU

- PGE trades increase in EDAM by ~2,100 GWh with California (via Malin) and ~2,300 GWh with PACW and PAWA, and PGE facilitates EDAM market exports via Mid-C
  - *PACW trades through PGE out to BPA and NWMT account for majority of Mid-C trade increase*
- PGE EDAM benefits of $10.6 million/yr driven largely by EDAM transfer revenues and savings from displacing internal generation with market purchases, offset by lower WEIM revenues

Portland General Electric Total Trading (All Types - GWh)

Partner	BAU		WEIM Transition	
	Exports	Imports	Exports	Imports
BPAT	714	447	962	432
PACW	459	746	1,114	1,033
PAWA	486	27	838	1,087
SCL	211	22	133	36
PSEI	421	275	314	345
MidC	1,650	3,417	4,912	7,904
Malin	827	2,977	2,434	3,478
Total	**4,769**	**7,912**	**10,709**	**14,315**

WEIM Transition Market Footprints



RTO West and/or WEIS Member
EDAM and WEIM Member
WEIM-Only Member
Non-Market BA

Bookend EDAM Case

Bookend EDAM case assumes all WECC entities contemplating joining a day-ahead market and not in RTO West or WEIS join EDAM, except for BCHA and TIDC which remain only in WEIM

- Entities that join EDAM assumed to join or remain in WEIM

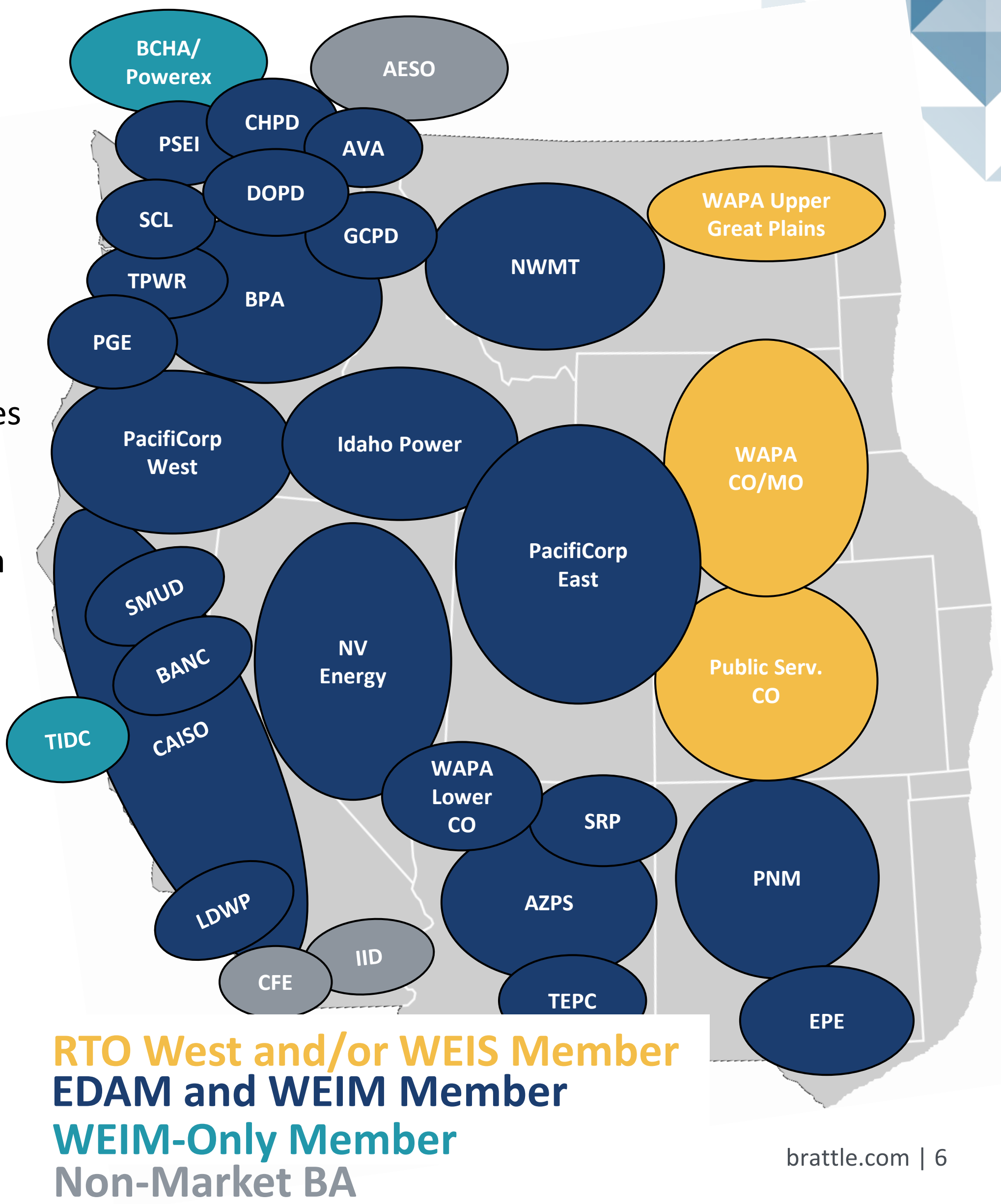
PGE trading & benefits dynamics relative to BAU

- PGE trading picks up in relative to BAU as all partners join EDAM, with biggest increases coming in PNW, esp. BPA, with direct market trades displacing trades through Mid-C
- PGE EDAM benefits of $17.5 million/yr driven largely by EDAM transfer revenues and savings from displacing internal generation with market purchases, offset by decline in WEIM revenues

Portland General Electric Total Trading (All Types - GWh)

Partner	BAU		Bookend EDAM	
	Exports	Imports	Exports	Imports
BPAT	714	447	1,114	3,264
PACW	459	746	527	1,087
PAWA	486	27	1,155	728
SCL	211	22	541	560
PSEI	421	275	755	329
MidC	1,650	3,417	0	588
Malin	827	2,977	1,492	2,642
Total	**4,769**	**7,912**	**5,585**	**9,199**

Bookend EDAM Market Footprints



EDAM Split Case

EDAM Split assumes PGE, IPCO, NVE, and SCL join EDAM with the entities that have announced they are joining EDAM, the Phase 1 Funders not in EDAM join Markets+, and other entities remain as they are in the BAU case

- Entities that join EDAM assumed to remain in WEIM
- Entities that join Markets+ assumed to join a Markets+ RT market

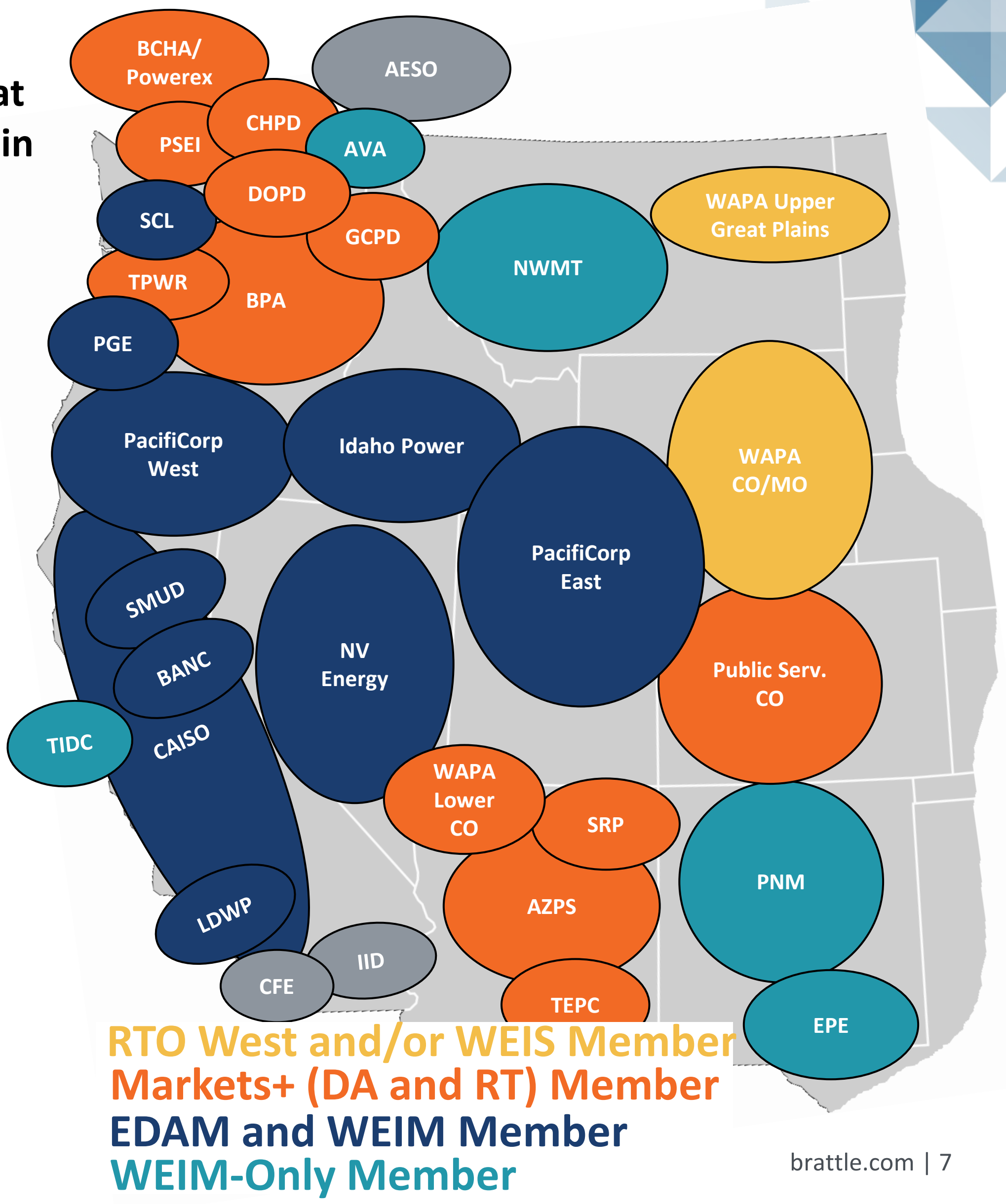
PGE trading & benefits dynamics relative to BAU

- PGE trades increase in EDAM by ~2,900 GWh with PACW/PAWA and 1,500 GWh with California, importing solar midday and exporting hydro and other resources overnight
  - *PGE facilitates trades out of EDAM footprint, accounting for increased volumes at Mid-C*
- PGE EDAM benefits of $6.6 million/yr driven largely by EDAM transfer revenues and offset by lower sales and sales revenues in the market & lower WEIM revenues

Portland General Electric Total Trading (All Types - GWh)

Partner	BAU		EDAM Split	
	Exports	Imports	Exports	Imports
BPAT	714	447	95	520
PACW	459	746	710	2,259
PAWA	486	27	1,321	337
SCL	211	22	235	254
PSEI	421	275	30	14
MidC	1,650	3,417	2,731	6,461
Malin	827	2,977	2,907	2,570
Total	**4,769**	**7,912**	**8,028**	**12,416**

EDAM Split Market Footprints



Markets+ Split Case

Markets+ Split assumes PGE and the Phase 1 Funders plus IPCO join Markets+, and other entities remain as they are in the BAU case

- Entities that join EDAM assumed to remain in WEIM
- Entities that join Markets+ assumed to join or shift to a Markets+ RT market

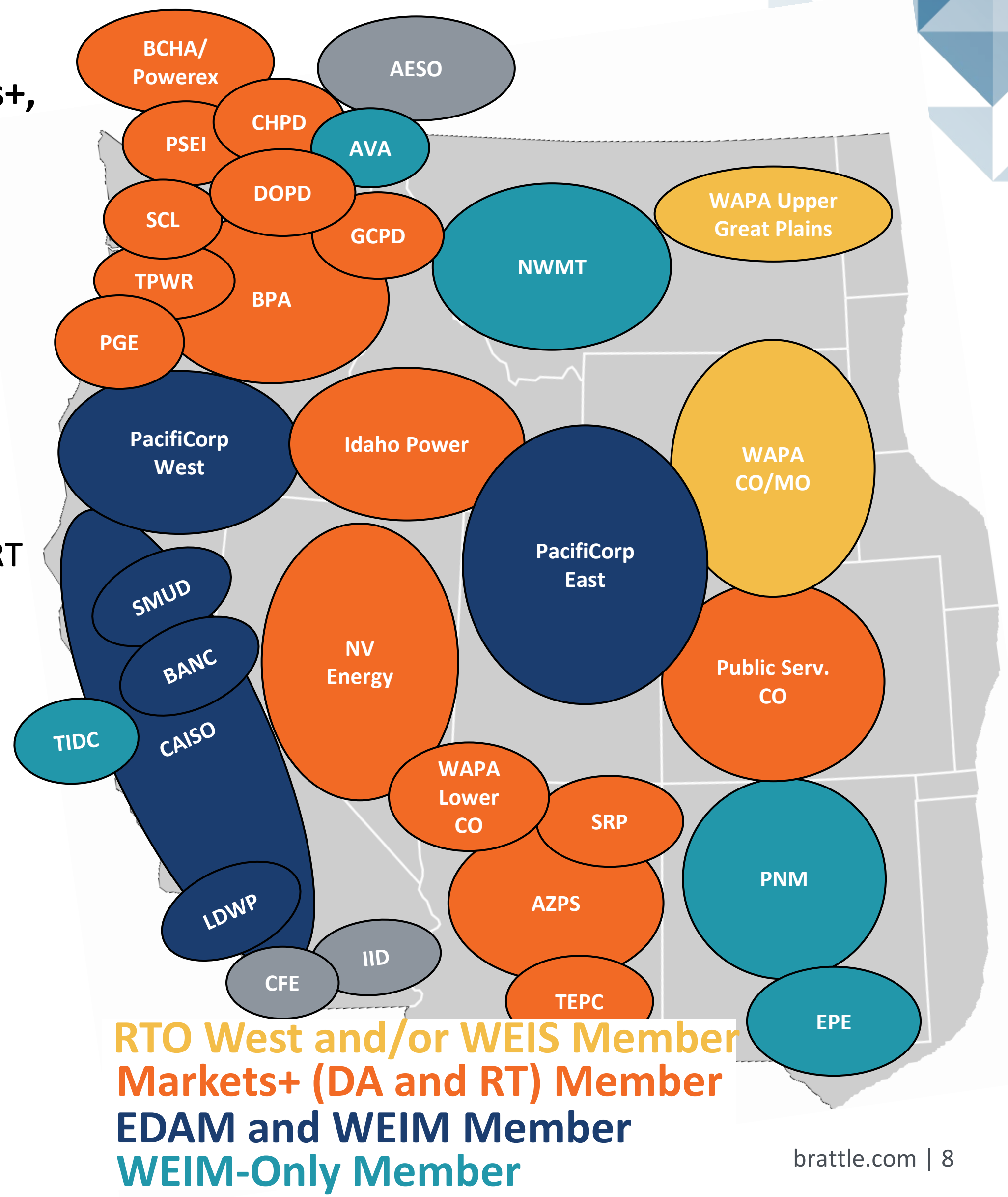
PGE trading & benefits dynamics relative to BAU

- PGE trading increases in Markets+ especially with BPAT (~6,900 GWh) displacing bilateral & WEIM trades with CAISO and PACW/PAWA
- PGE M+ benefits of $8.7 million/yr driven largely by savings from displacing internal generation with market purchases & M+ transfer revenues, offset by loss of ~75% of RT revenue from shifting out of the WEIM into Markets+ RT

Portland General Electric Total Trading (All Types - GWh)

Partner	BAU		Markets+ Split	
	Exports	Imports	Exports	Imports
BPAT	714	447	3,604	4,464
PACW	459	746	335	158
PAWA	486	27	0	24
SCL	211	22	15	118
PSEI	421	275	235	206
MidC	1,650	3,417	1,508	3,446
Malin	827	2,977	0	1,131
Total	**4,769**	**7,912**	**5,698**	**9,546**

Markets+ Split Market Footprints



Bookend Markets+ Case

Bookend Markets+ assumes the entities that have announced they are joining EDAM go to EDAM, PGE goes to Markets+ with most of the remaining WECC BAs, and other entities remain as they are in the BAU case

- Entities that join EDAM assumed to remain in WEIM
- Entities that join Markets+ assumed to join or shift to a Markets+ RT market

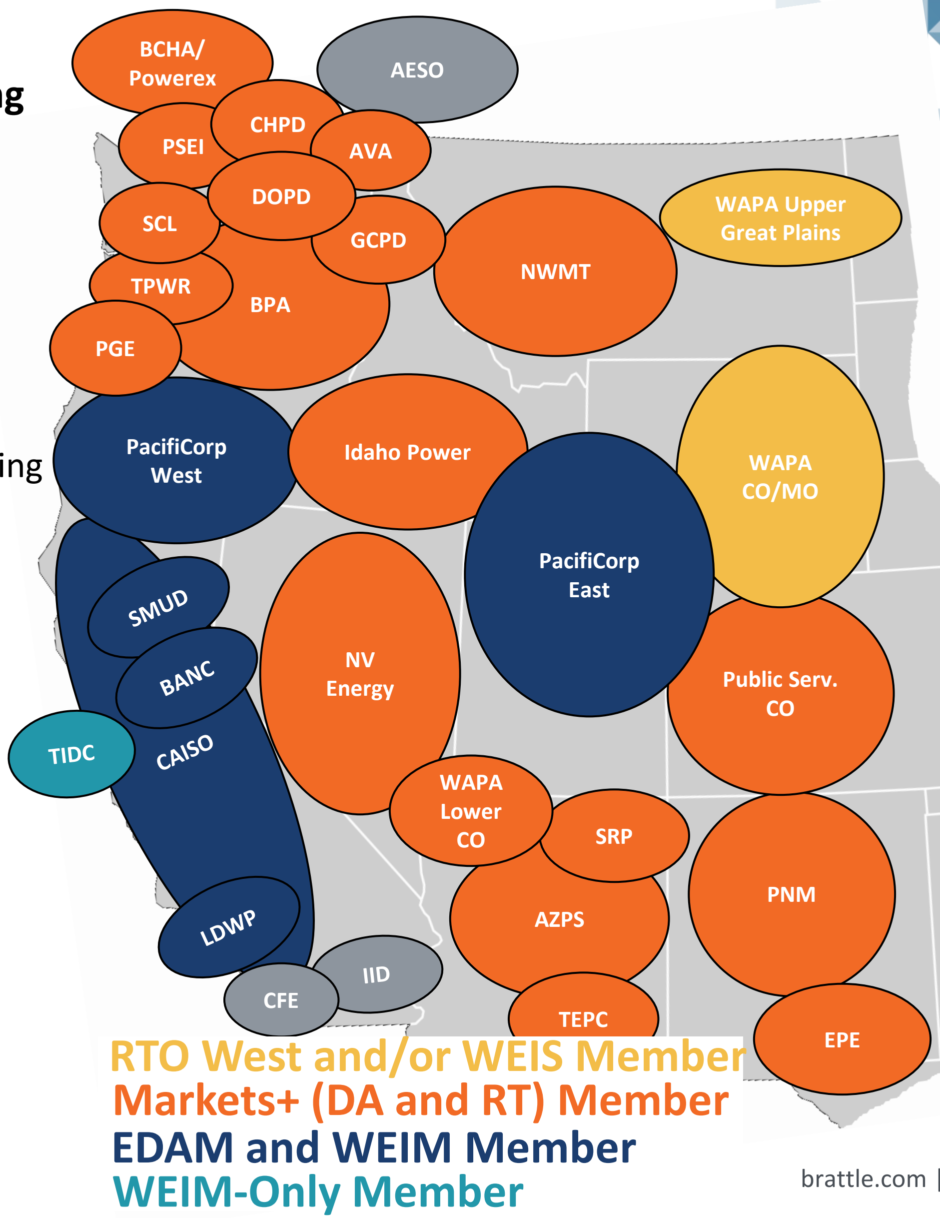
PGE trading & benefits dynamics relative to BAU

- PGE trading increases in Markets+ especially with BPAT (~5,400 GWh increase) displacing bilateral & WEIM trades with CAISO and PACW/PAWA
- PGE M+ benefits of $8.3 million/yr driven largely by savings from displacing internal generation with market purchases, increased sales revenue, & M+ transfer revenue, offset by loss of ~75% of RT revenue from shifting out of the WEIM into Markets+ RT

Portland General Electric Total Trading (All Types - GWh)

Partner	BAU		Bookend Markets+	
	Exports	Imports	Exports	Imports
BPAT	714	447	3,241	3,294
PACW	459	746	329	220
PAWA	486	27	0	34
SCL	211	22	16	158
PSEI	421	275	180	223
MidC	1,650	3,417	1,061	3,350
Malin	827	2,977	0	1,194
Total	**4,769**	**7,912**	**4,827**	**8,474**

Bookend Markets+ Market Footprints



PGE Trading Volumes Summary

PGE trading volumes similar in Bookend Cases, but tend to be higher in EDAM in other cases

- Markets+ trading volumes highest with BPA, with which PGE has the most trading capability in that market
- PGE's largest trading partners in EDAM tend to be PAC and CAISO / BANC via Malin
  - When EDAM footprint is limited, PGE facilitates trades out of the market footprint via Mid-C
  - When footprint is broad (e.g., EDAM Bookend), PGE trades favor direct paths with neighbors in the market, rather than trades through Mid-C

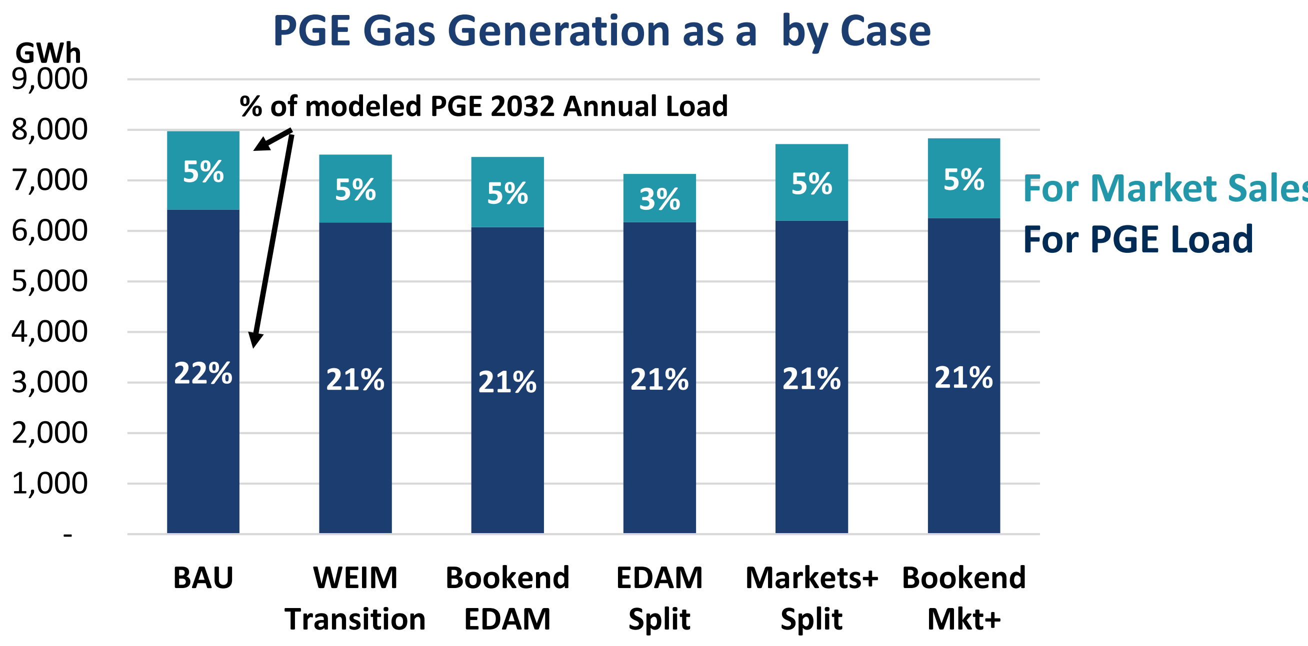
Portland General Electric Total Trading (All Types - GWh)

Partner	BAU		WEIM Transition		Bookend EDAM		EDAM Split		Markets+ Split		Bookend Markets+	
	Exports	Imports	Exports	Imports	Exports	Imports	Exports	Imports	Exports	Imports	Exports	Imports
BPAT	714	447	962	432	1,114	3,264	95	520	3,604	4,464	3,241	3,294
PACW	459	746	1,114	1,033	527	1,087	710	2,259	335	158	329	220
PAWA	486	27	838	1,087	1,155	728	1,321	337	0	24	0	34
SCL	211	22	133	36	541	560	235	254	15	118	16	158
PSEI	421	275	314	345	755	329	30	14	235	206	180	223
MidC	1,650	3,417	4,912	7,904	0	588	2,731	6,461	1,508	3,446	1,061	3,350
Malin	827	2,977	2,434	3,478	1,492	2,642	2,907	2,570	0	1,131	0	1,194
Total	**4,769**	**7,912**	**10,709**	**14,315**	**5,585**	**9,199**	**8,028**	**12,416**	**5,698**	**9,546**	**4,827**	**8,474**

PGE Gas Generation Impacts

PGE's gas fleet annual generation relatively consistent across scenarios

- We modeled PGE's unit costs and fuel limitations, but not direct generation or emissions limits
- PGE gas generation attributable to PGE load exceeds ~20% of load in all cases, though by a small margin
- Market sales of gas generation tend to be more valuable in Markets+, which has a more thermal-heavy footprint-wide supply mix



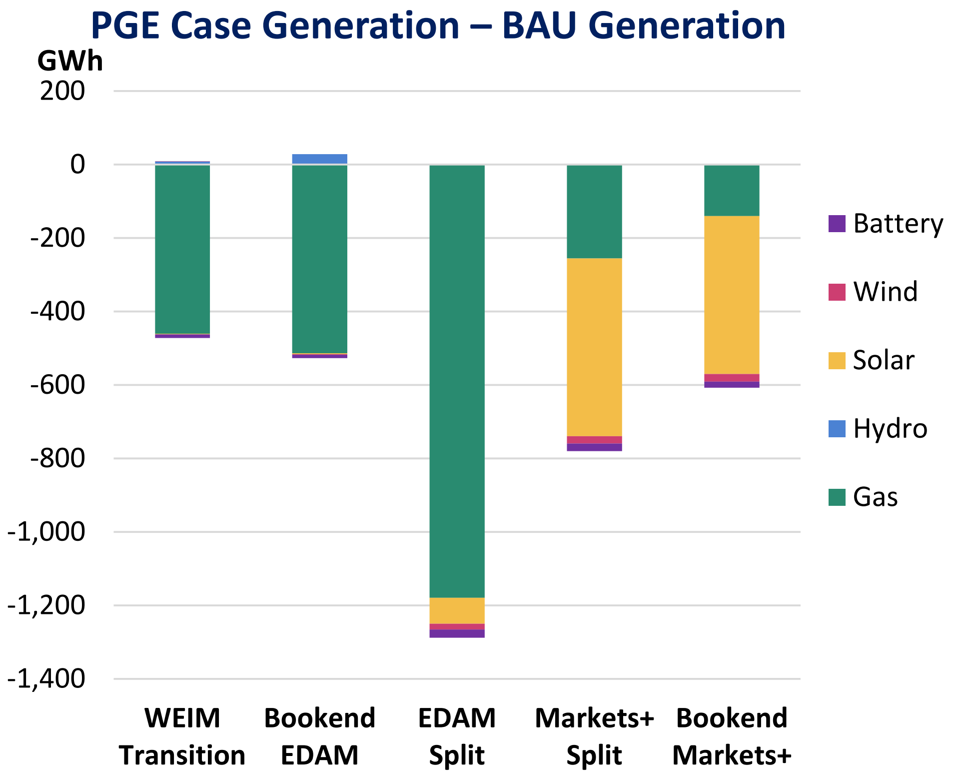
PGE Generation Mix Impacts

EDAM cases show largest reduction in gas generation

- Access to markets allows PGE to reduce gas generation and purchase cheaper largely renewable power from the market
- Gas generation ramps down more in EDAM than Markets+ cases as due to the greater surplus of midday solar in the footprint

Markets+ cases show largest solar curtailment

- Markets+ produces solar curtailments in PGE's footprint due to limited connectivity in the Markets+ footprint, especially between the PNW and Southwest
  - As Markets+ footprint grows solar curtailments in PGE decline but exceed the renewable curtailments for the cases in which PGE is in EDAM
    - 501 GWh solar curtailment in Markets+ Split
    - 447 GWh solar curtailment in the Markets+ Bookend case



Additional Results

Hurdle Rate Assumptions

Hurdle rates vary by trade type, decision timeframe, and whether trade involves GHG transfers

- Hourly bilateral trading friction $6 in the dispatch cycle, $16 in unit commitment cycle
  - $10/MWh adder in commitment vs dispatch prevents over-optimization of commitment
- Block trading at hubs and intertie transactions charged lower trading friction due to greater ease of execution for such trades vs hourly bilateral trades
- Bilateral or intertie trades into GHG regions charge unspecified resources rate of ~$28/MWh
- Within the EDAM, EIM, and Markets+ (DA and RT) footprints, trades into GHG region charged resource-type-specific GHG charges

Cost of Transactions by Type ($/MWh)

Trade Type		Decision Timeframe	Trading Friction	GHG Pricing	OATT Charge	Total Charge
Block Trades	With ETC Rights	Day-Ahead	$1.50	Generic Import Cost **$28/MWh** *(Based on CA Rule)*	$0	$1.5 + *GHG*
	Without ETC Rights	Day-Ahead	$1.50		$1.03	$2.53 + *GHG*
Hourly BA-BA Trades	With ETC Rights	Day-Ahead	$16 Commitment, $6 Day-Ahead		$0	$6 - $16 + *GHG*
	Without ETC Rights	Day-Ahead	$16 Commitment, $6 Day-Ahead		$1.03	$7.03 - $17.03 + *GHG*
CAISO Intertie Trade	With ETC Rights	Day-Ahead	$1.50		$0	$1.5 + *GHG*
	Without ETC Rights	Day-Ahead	$1.50		$1.03	$2.53 + *GHG*
EDAM	EDAM Trades	Day-Ahead	$0.00	Resource-Type Specific Cost	$0	$0 + *GHG*
Markets+	Markets+ Trades	Day-Ahead	$0.00		$0	$0 + *GHG*
EIM Market	EIM Trades	Real-Time	$0.00		$0	$0 + *GHG*
WEIS Market	WEIS Trades	Real-Time	$0.00		$0	$0 + *GHG*

Notes: "Commitment" refers to the stage of the model that makes unit commitment decisions right before running day-ahead dispatch results.

Transmission Utilization Rates

PGE’s trading path utilization tends to be higher in EDAM

- PGE imports from PACW and Malin are generally highest in the EDAM Split, in which the EDAM footprint is more limited
  - While Malin>PGE utilization is 55% in this case, but with flow almost entirely midday
  - Spring utilization midday averages 70-90%
- Even with BPAT>PGE TTCs encumbered by BPA-located PGE generation coming home, significant trading headroom remains available on the path

Average Path TTC Utilization for PGE

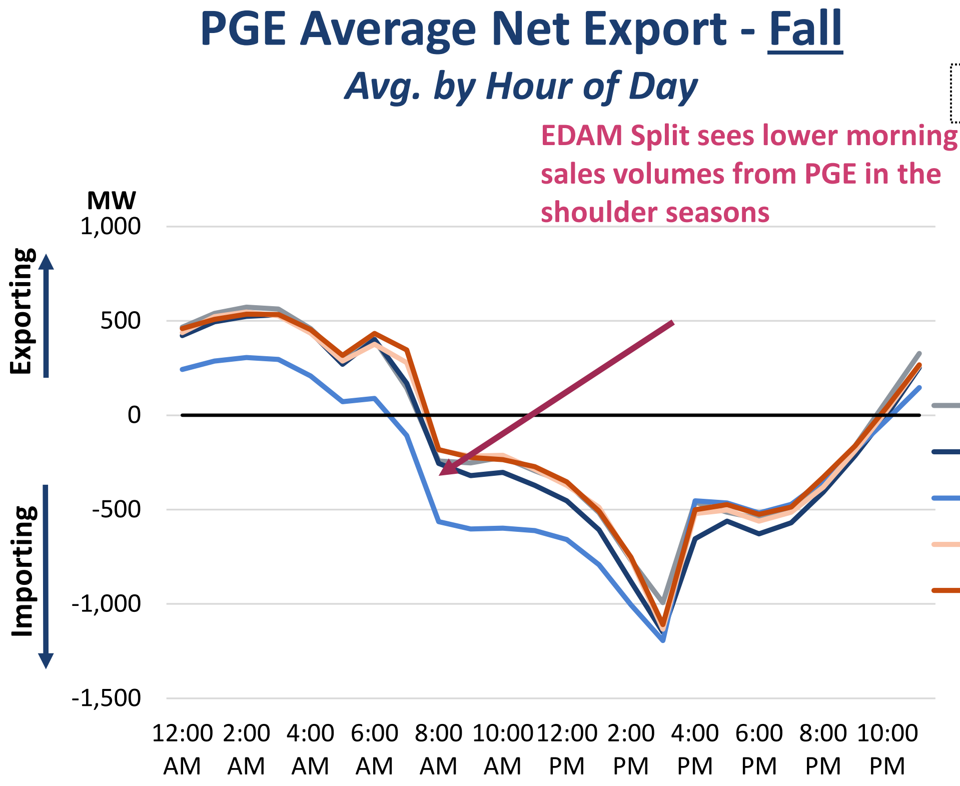
		BAU	WEIM Transition	Bookend EDAM	EDAM Split	Markets+ Split	Bookend Markets+
Export Paths							
PGE	PACW	12%	32%	30%	48%	8%	8%
PGE	BPAT	2%	6%	4%	5%	7%	6%
PGE	PSEI	48%	36%	86%	3%	27%	21%
PGE	SCL	67%	62%	78%	75%	71%	70%
PGE	Malin	10%	31%	19%	37%	0%	0%
Import Paths							
PACW	PGE	4%	42%	31%	62%	5%	7%
BPAT	PGE	53%	50%	57%	50%	57%	55%
PSEI	PGE	31%	39%	37%	2%	24%	37%
SCL	PGE	44%	61%	57%	72%	63%	62%
MidC	PGE	29%	43%	8%	54%	24%	30%
Malin	PGE	54%	63%	48%	47%	21%	22%

Notes:
1: BPAT imports to PGE includes PGE owned generation in BPAT’s territory that encumbers TTC.
2: Malin to PGE and vice-versa includes the CAISO EIM transfers.

PGE Net Exports and Sales Revenue (Fall Example)

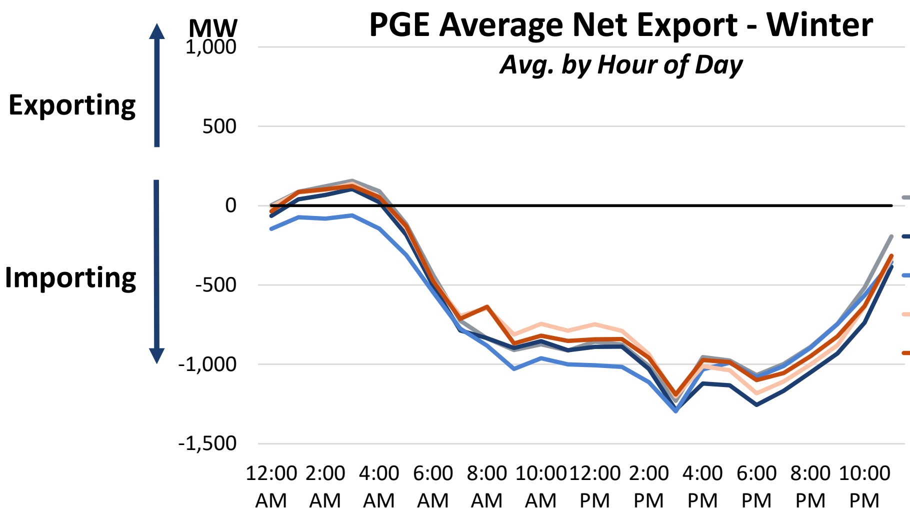
PGE consistently selling at night, seeking opportunities to displace less efficient gas generation in the market footprints

- EDAM Split seeing lowest PGE sales contributing to the reduced PGE adjusted production cost benefit in that case
  - These reduced sales comes mainly in Aug-Oct and Feb-March, periods in which the more limited EDAM footprint in this case has higher supply of renewables / hydro, and thus lower need for gas generation
  - For example, the Markets+ Split footprint in September is 36% gas and coal generation, whereas the EDAM Split footprint is just 10% gas and coal



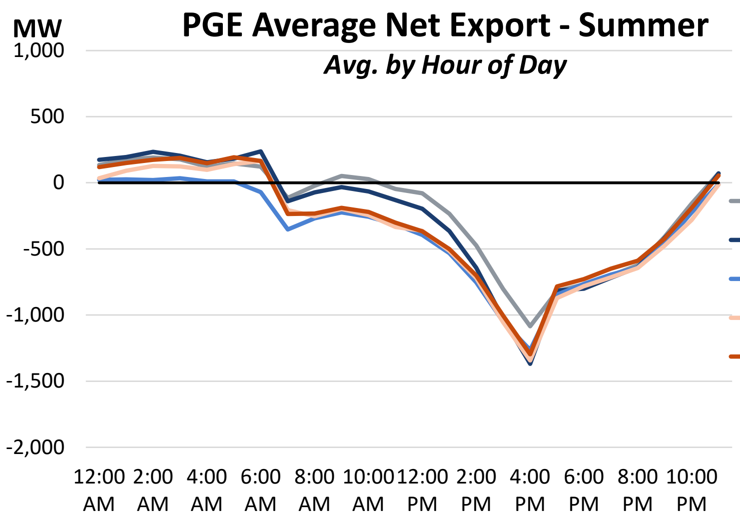
Sales Revenue	
$/MWh	$ Mil.
$47	$44
$47	$45
$44	$26
$45	$42
$47	$45

PGE Net Exports and Sales Revenue (All Seasons)



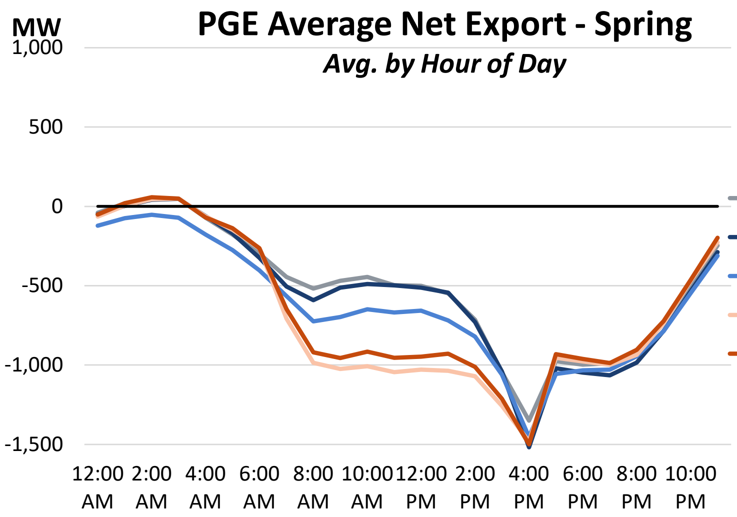
Sales Revenue

	$/MWh	$ Mil.
BAU	$48	$27
BK EDAM	$46	$28
EDAM Split	$45	$19
Markets+ Split	$47	$29
BK Markets+	$48	$29



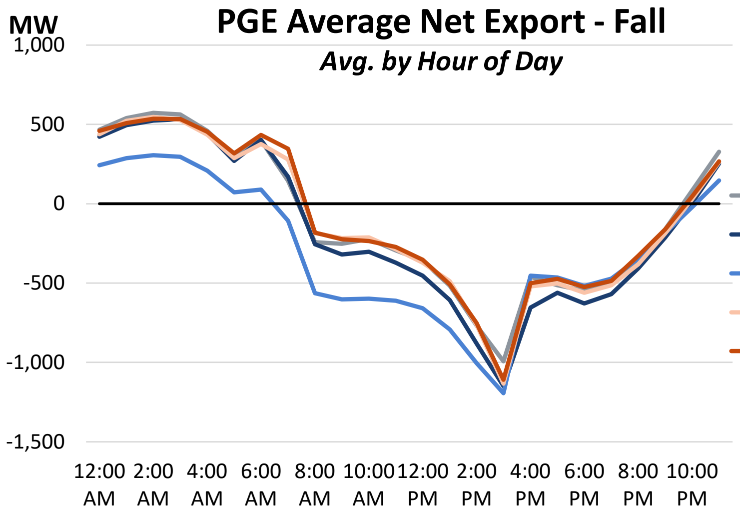
Sales Revenue

	$/MWh	$ Mil.
BAU	$35	$31
BK EDAM	$35	$30
EDAM Split	$31	$20
Markets+ Split	$36	$29
BK Markets+	$36	$30



Sales Revenue

	$/MWh	$ Mil.
BAU	$7	$5
BK EDAM	$3	$2
EDAM Split	$4	$2
Markets+ Split	$11	$7
BK Markets+	$12	$8



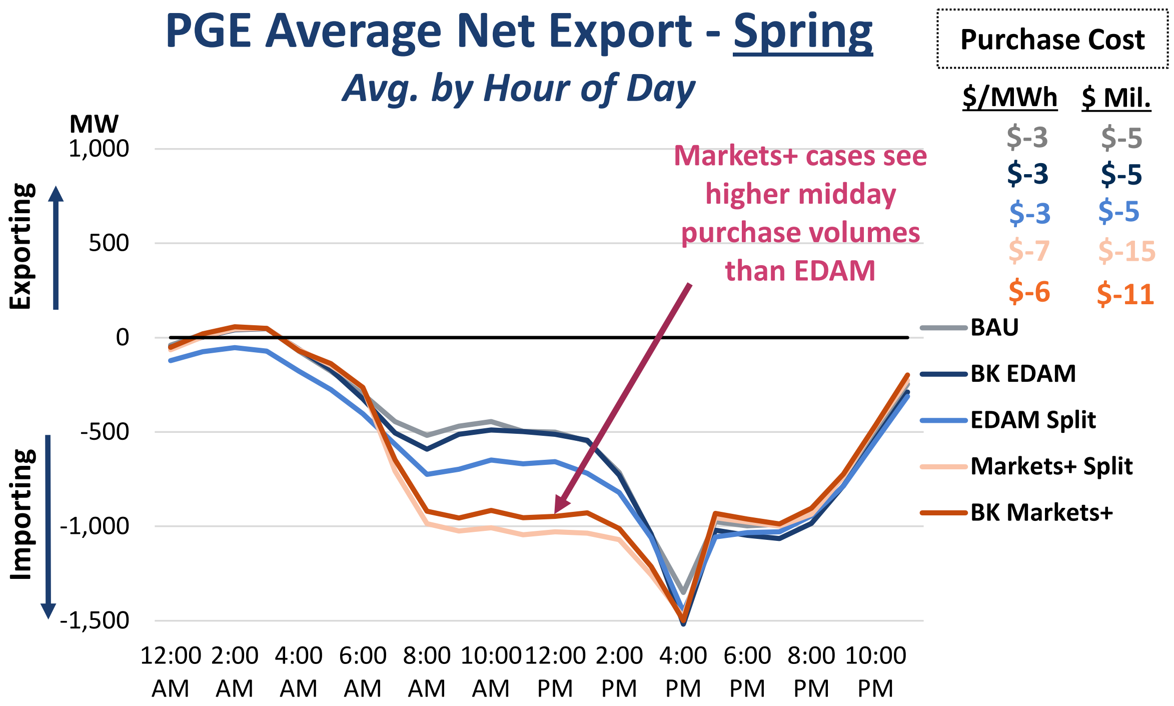
Sales Revenue

	$/MWh	$ Mil.
BAU	$47	$44
BK EDAM	$47	$45
EDAM Split	$44	$26
Markets+ Split	$45	$42
BK Markets+	$47	$45

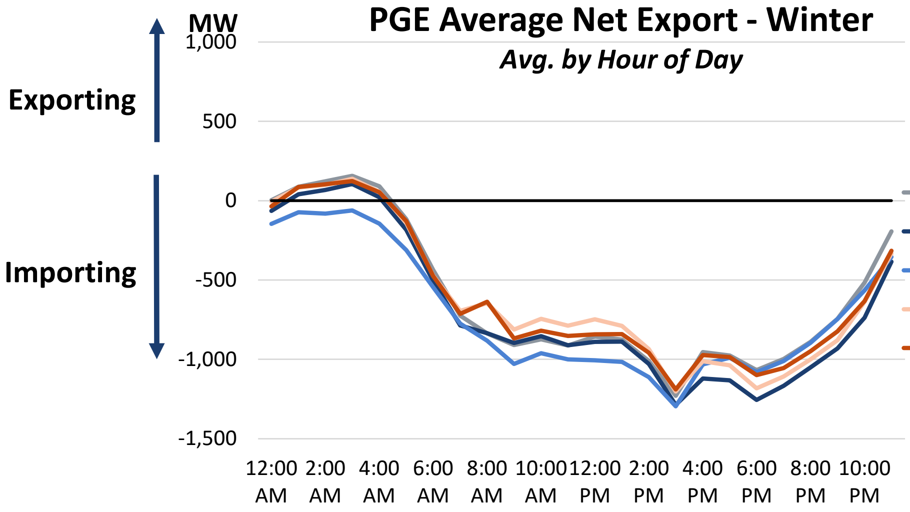
PGE Net Exports and Purchase Costs (Spring Example)

PGE consistently buys during the day and evening

- Markets+ generation mix in the spring is about as clean as EDAM's at about 90-92% zero-cost generation
  - This is because of strong hydro generation and Nevada/AZPS being large solar producers
  - PGE's high TTC with BPAT allows it in Markets+ to buy excess hydro and solar over the amount it can buy in EDAM
- In EDAM Split, PGE's imports from CAISO and PAC are somewhat transfer limited
  - TTC from Malin has an average utilization of 70-90% during solar hours, and its import path from PACW an average utilization 60-70%

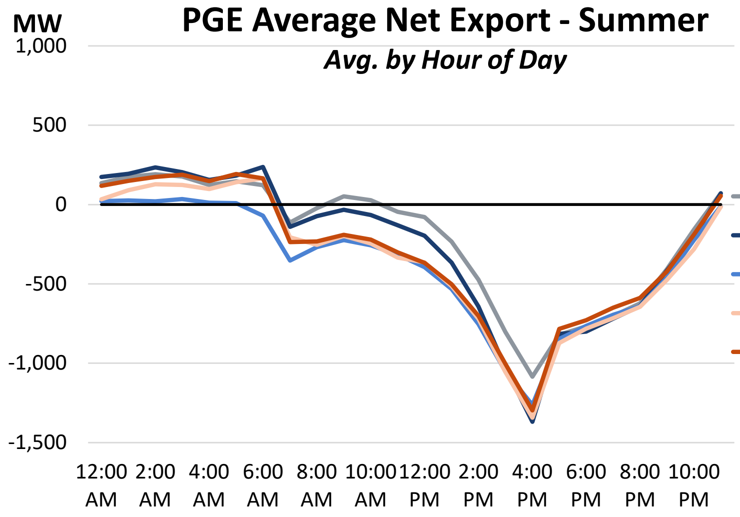


PGE Net Exports and Purchase Costs (All Seasons)



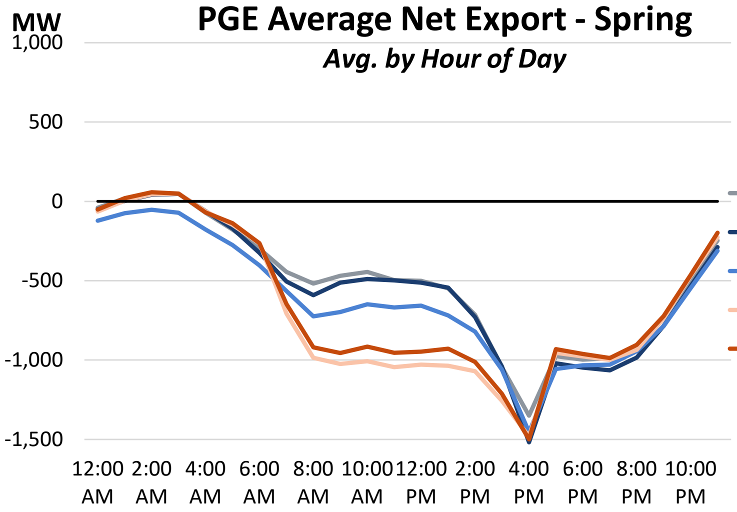
Purchase Cost

	$/MWh	$ Mil.
BAU	$55	$103
BK EDAM	$52	$110
EDAM Split	$55	$108
Markets+ Split	$54	$106
BK Markets+	$55	$107



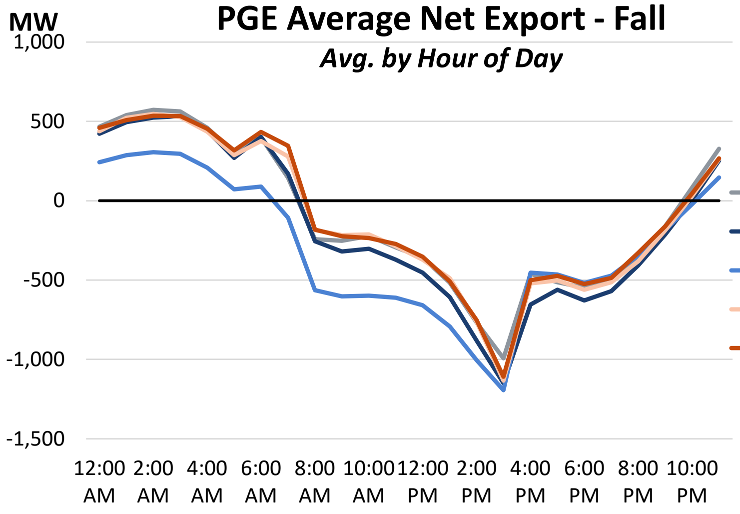
Purchase Cost

	$/MWh	$ Mil.
BAU	$11	$15
BK EDAM	$16	$22
EDAM Split	$13	$19
Markets+ Split	$10	$15
BK Markets+	$9	$14



Purchase Cost

	$/MWh	$ Mil.
BAU	$-3	$-5
BK EDAM	$-3	$-5
EDAM Split	$-3	$-5
Markets+ Split	$-7	$-15
BK Markets+	$-6	$-11

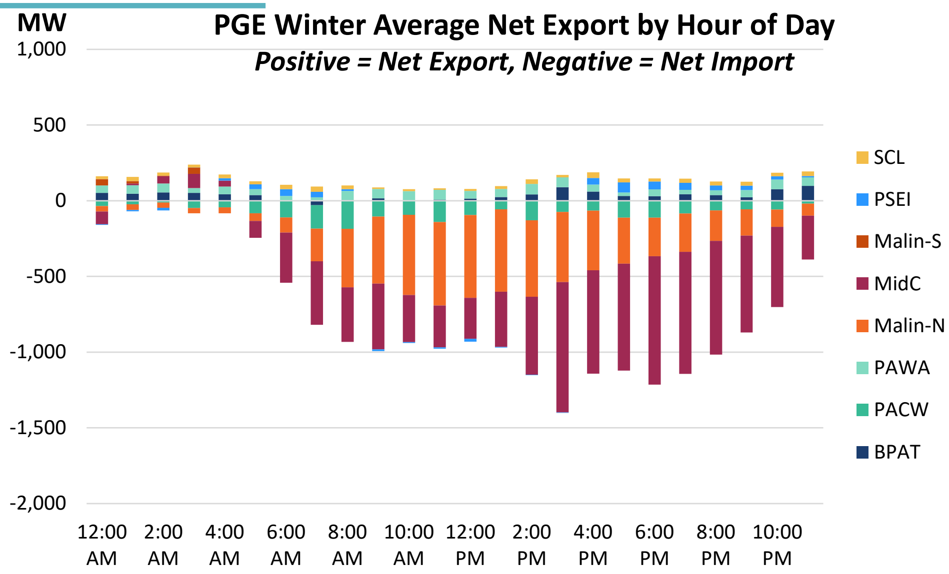


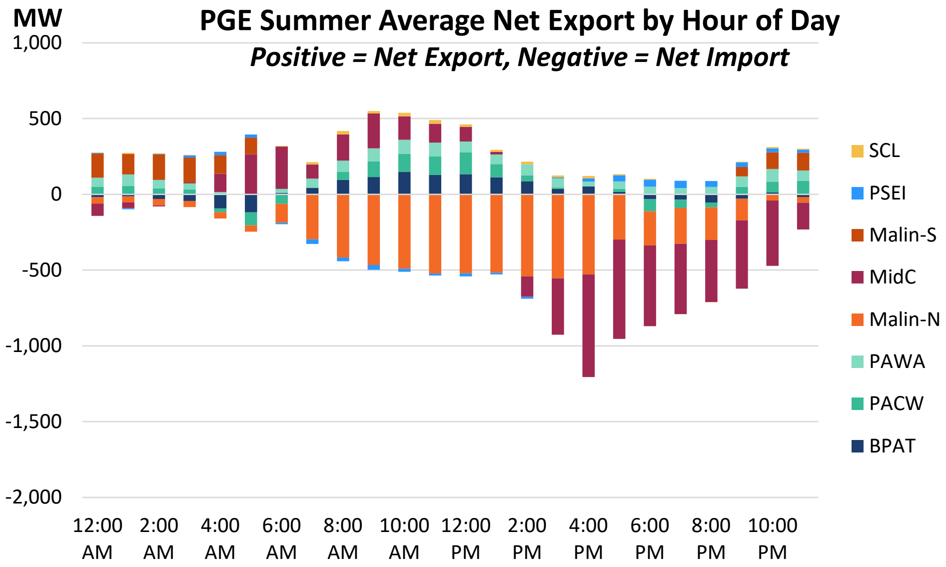
Purchase Cost

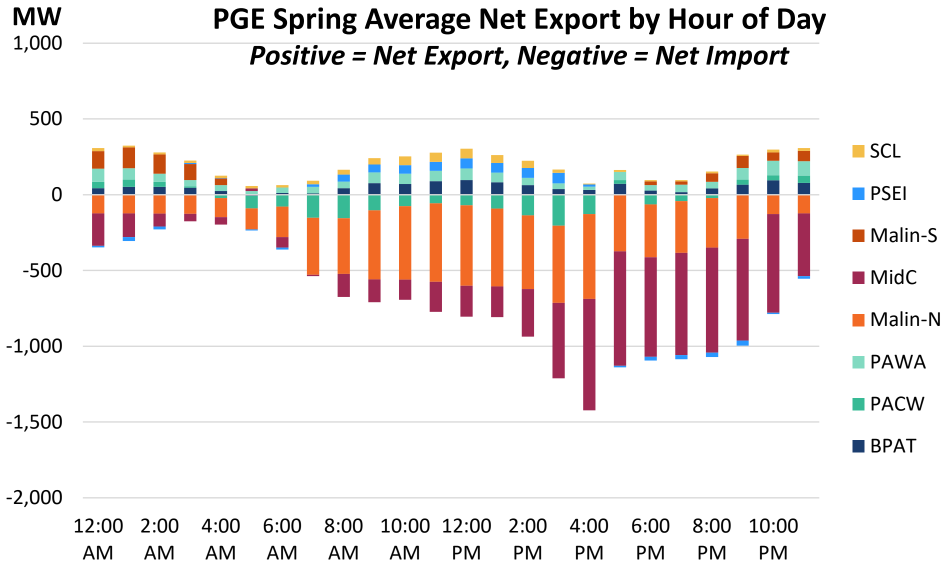
	$/MWh	$ Mil.
BAU	$44	$50
BK EDAM	$42	$55
EDAM Split	$41	$50
Markets+ Split	$43	$51
BK Markets+	$45	$52

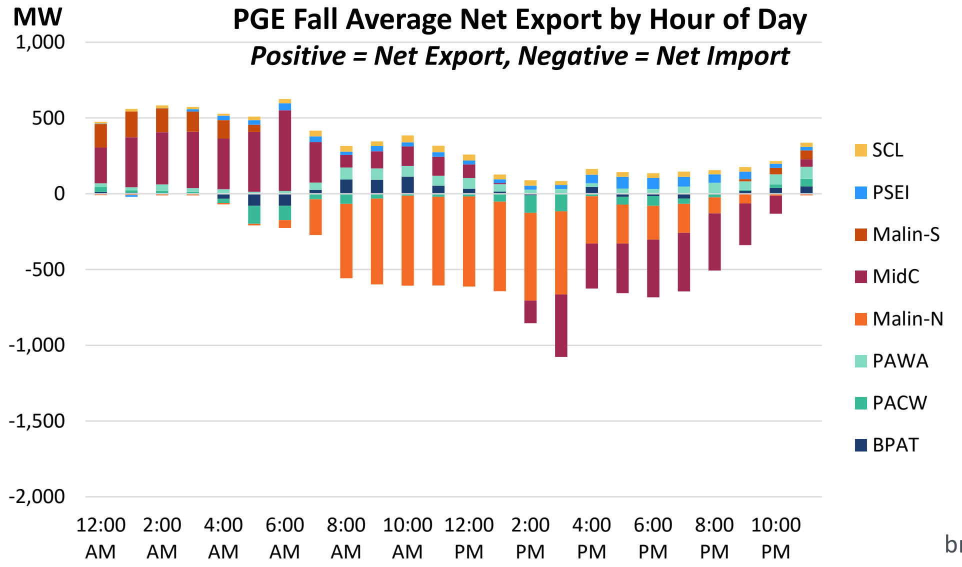
PGE Seasonal Trading Charts

BAU Case Trading (Seasonal)



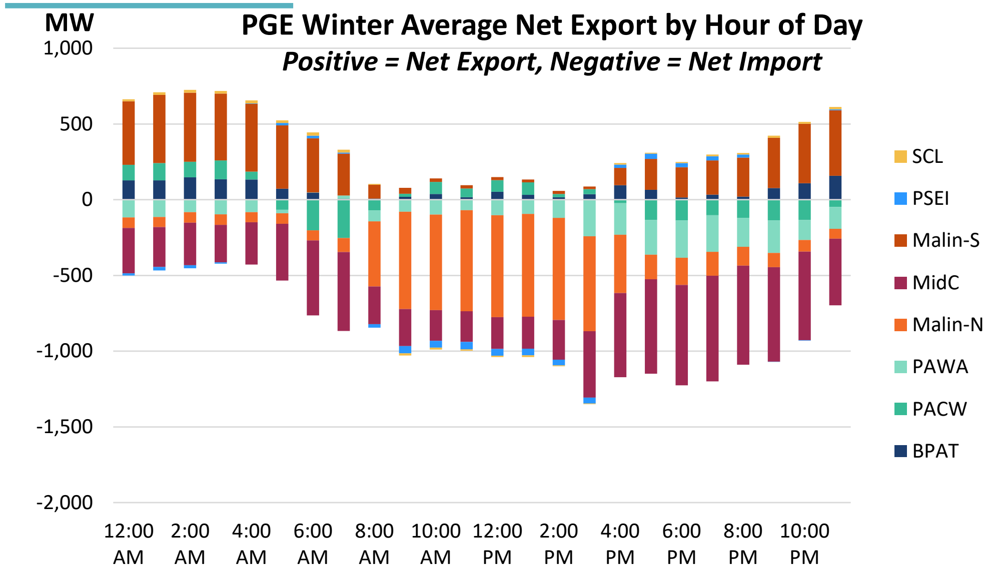


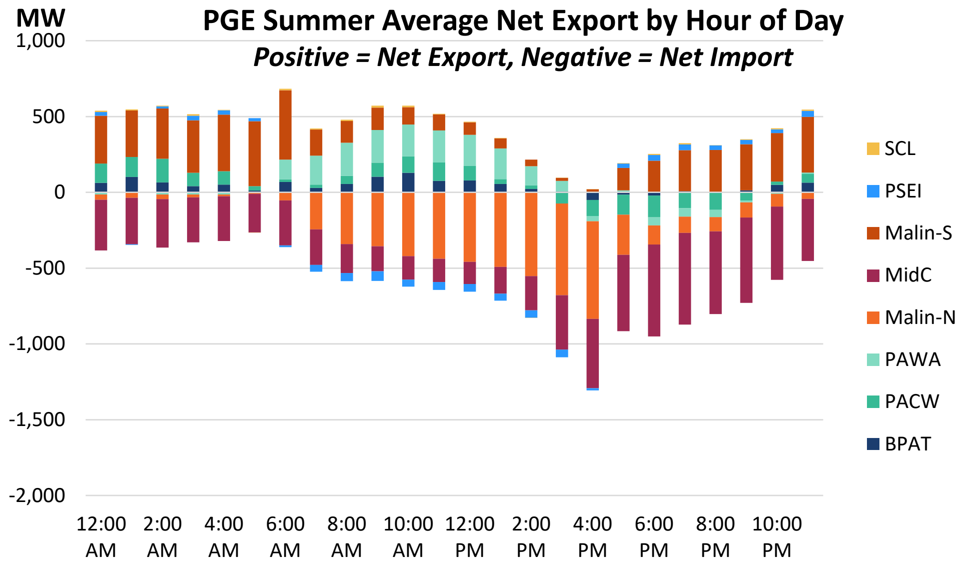


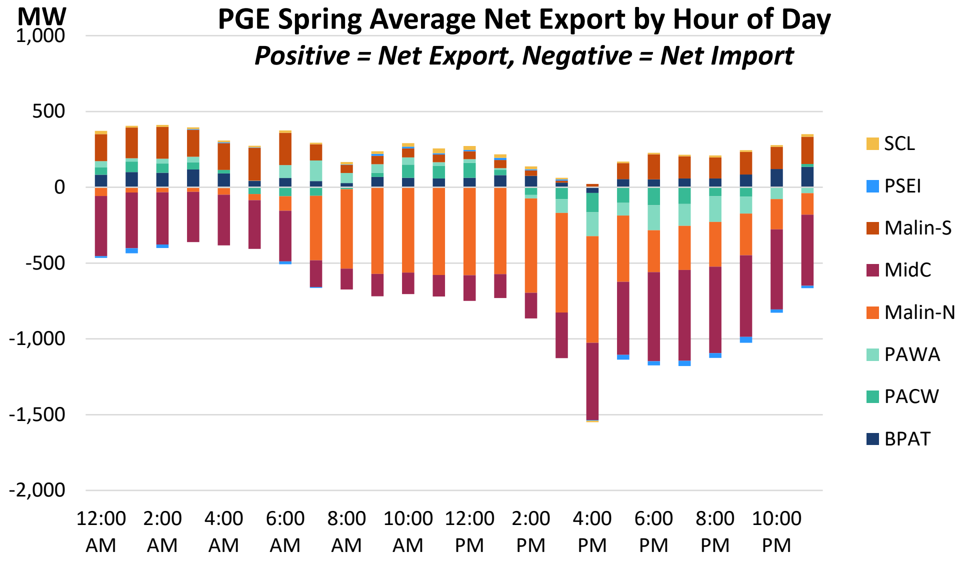


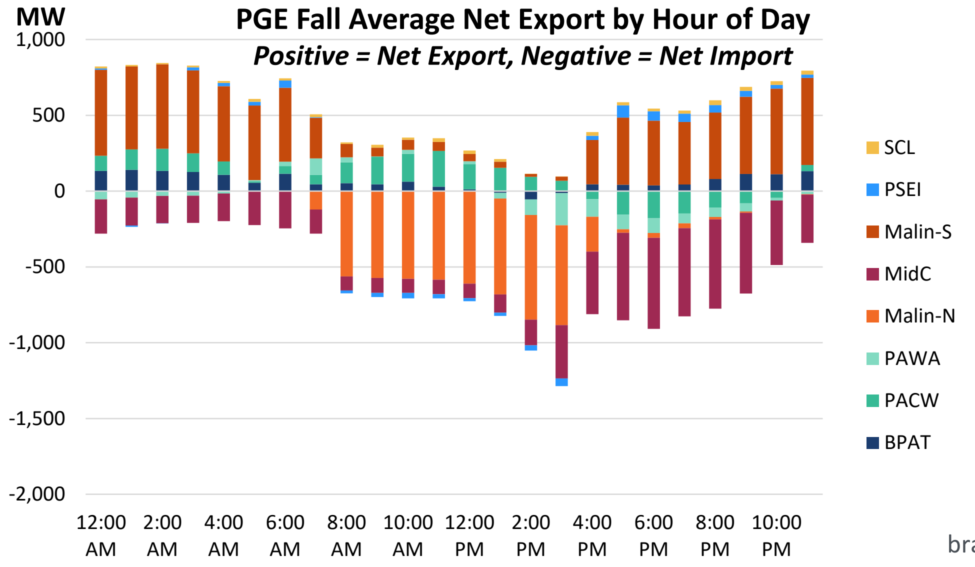
ADDITIONAL PGE RESULTS

WEIM Transition Case Trading (Seasonal)

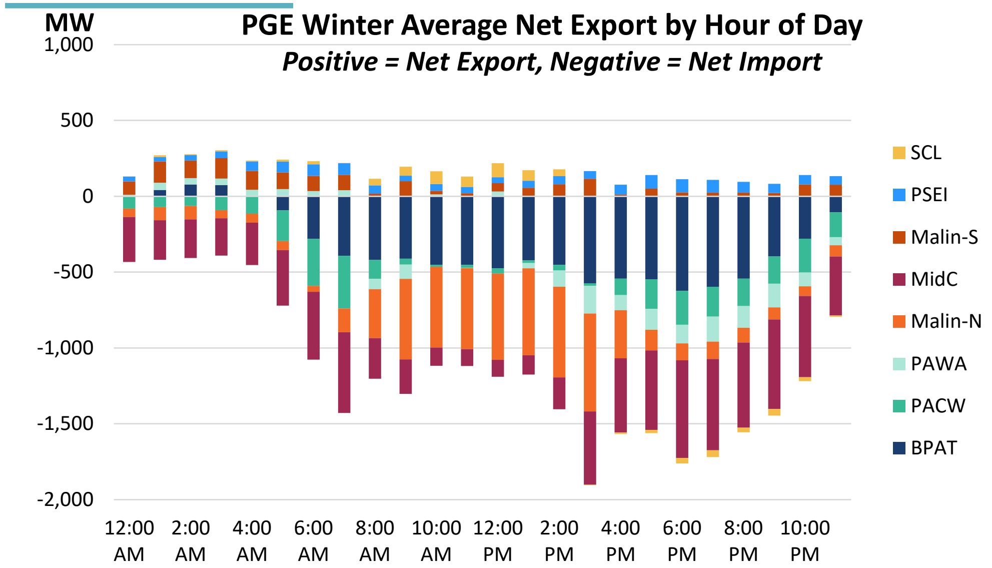


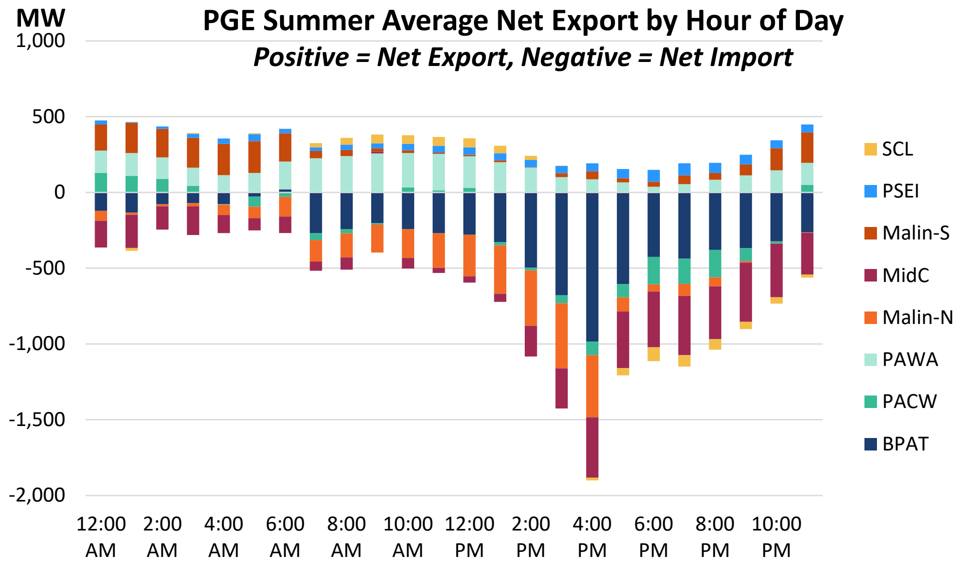


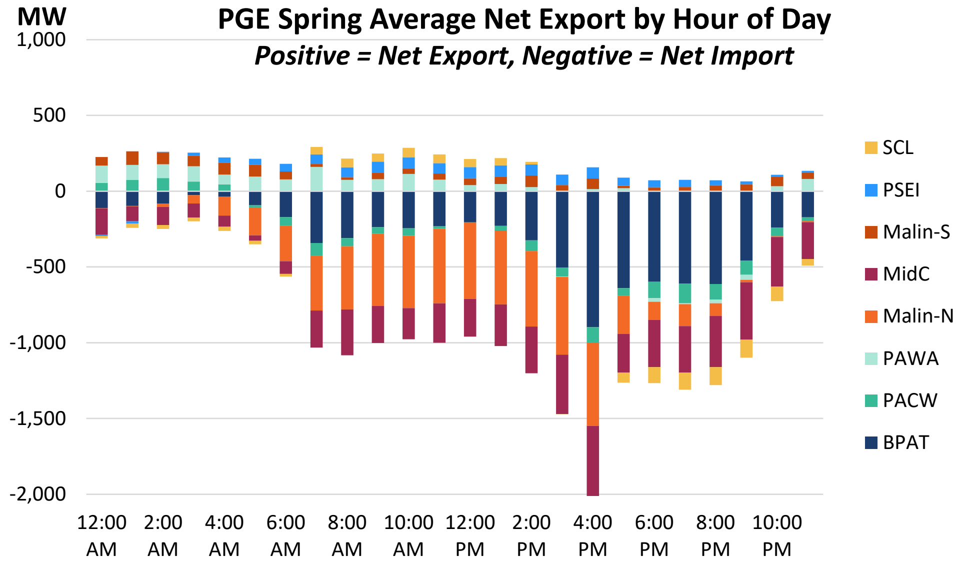


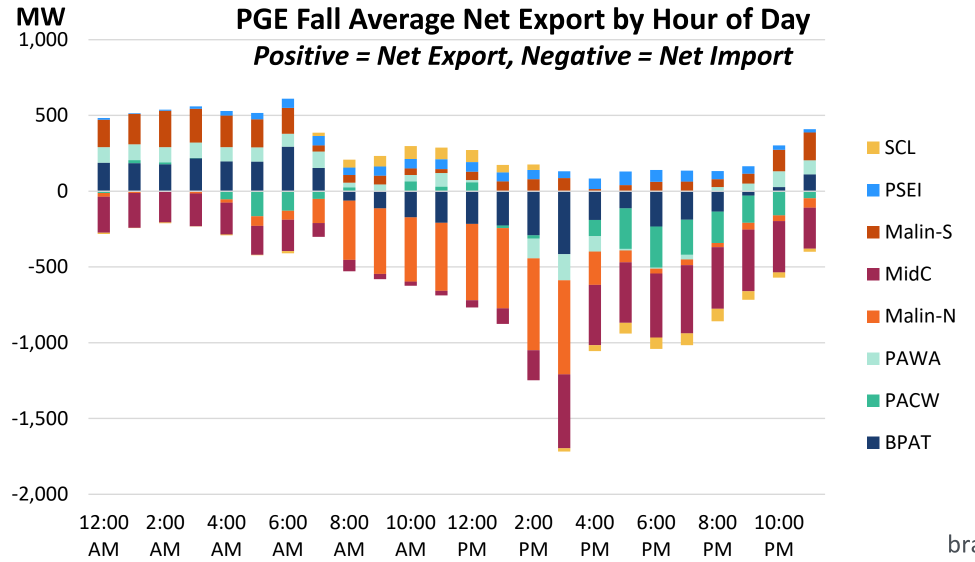


Bookend EDAM Case Trading (Seasonal)

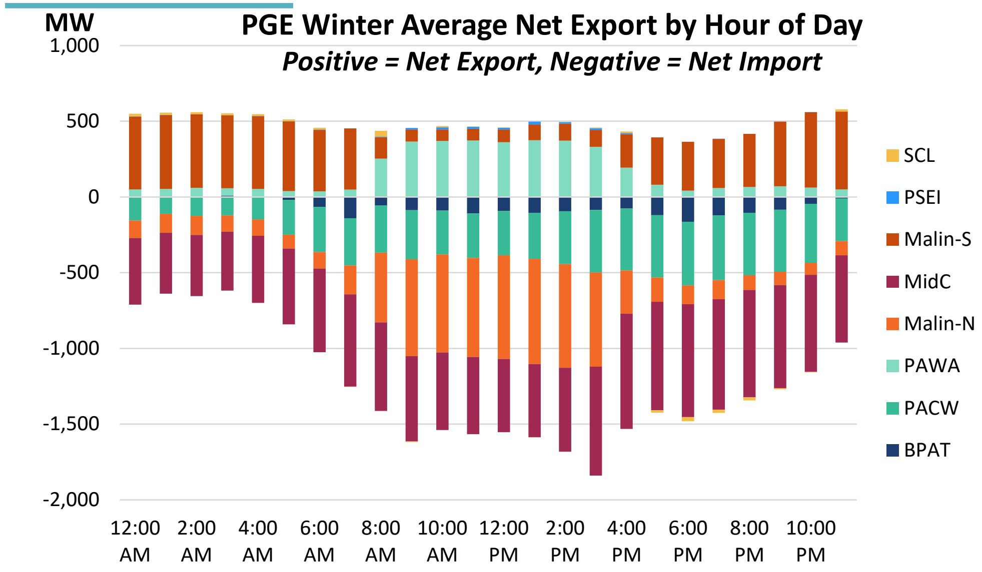


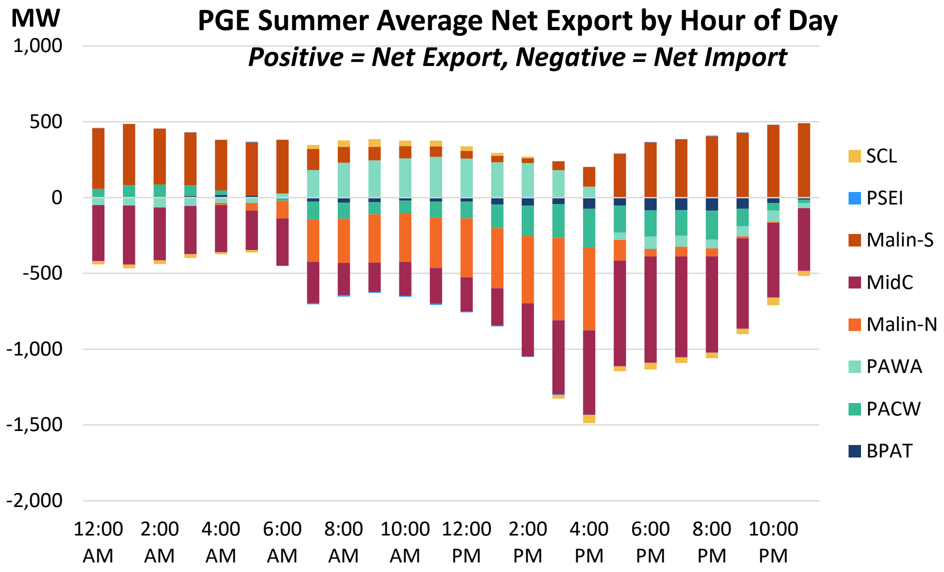


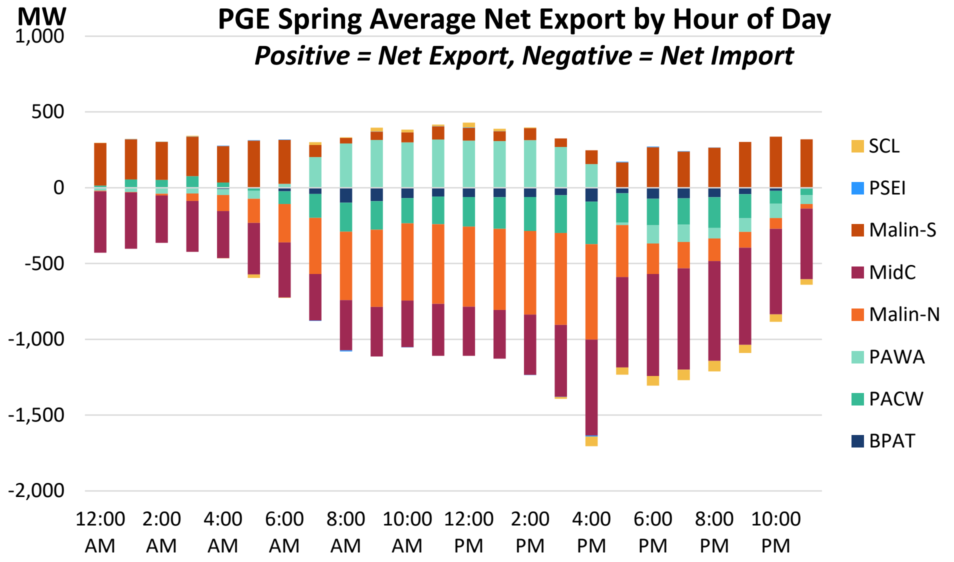


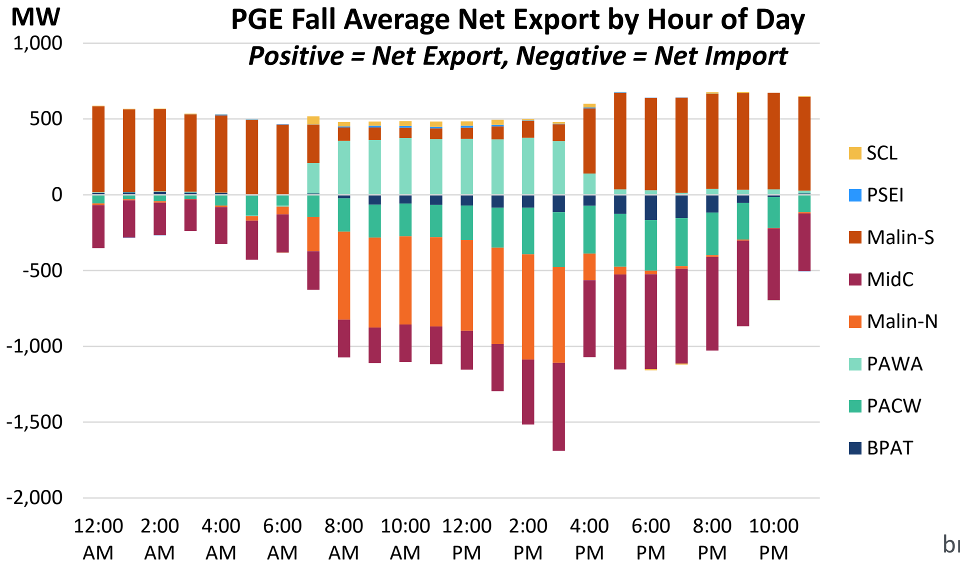


EDAM Split Case Trading (Seasonal)

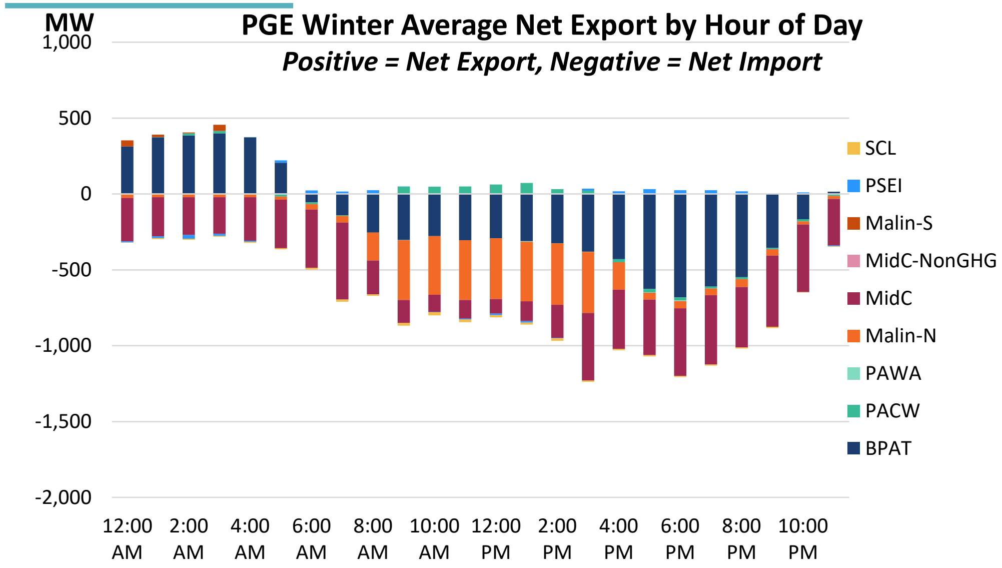


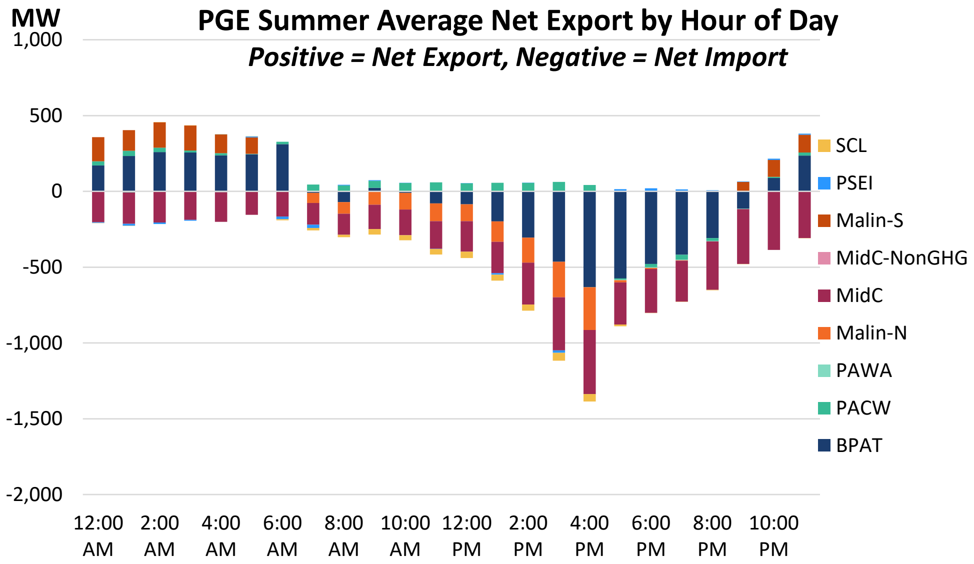


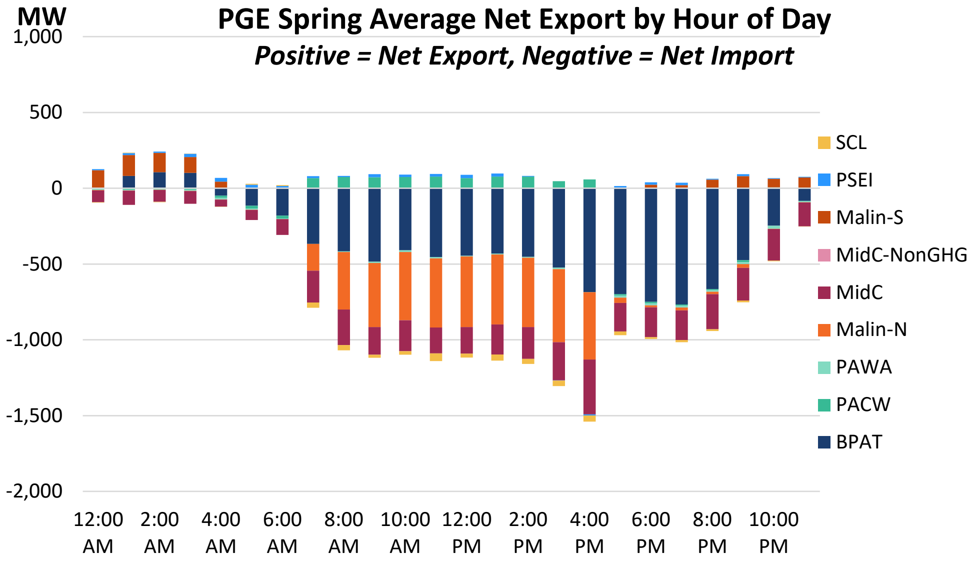


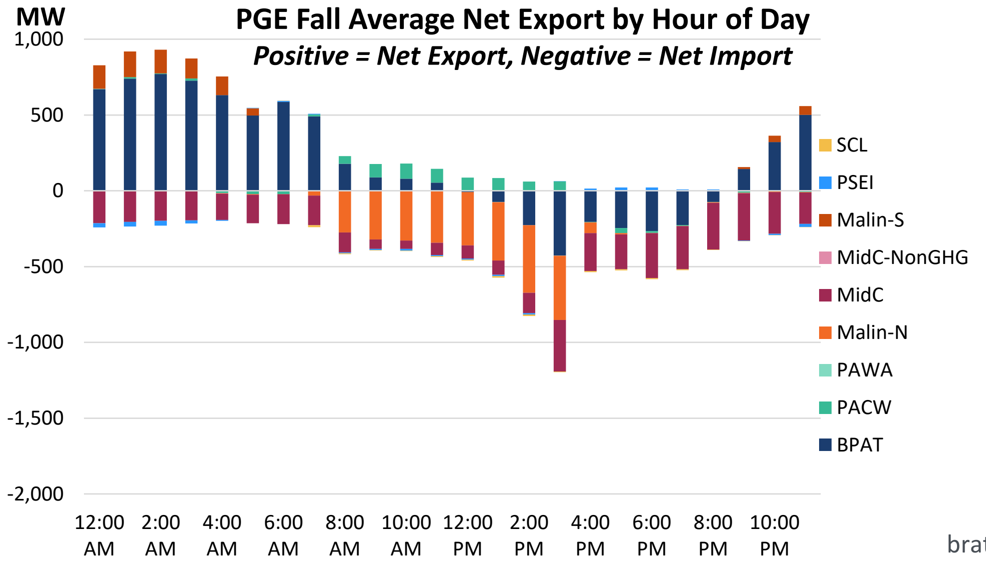


Markets+ Split Case Trading (Seasonal)



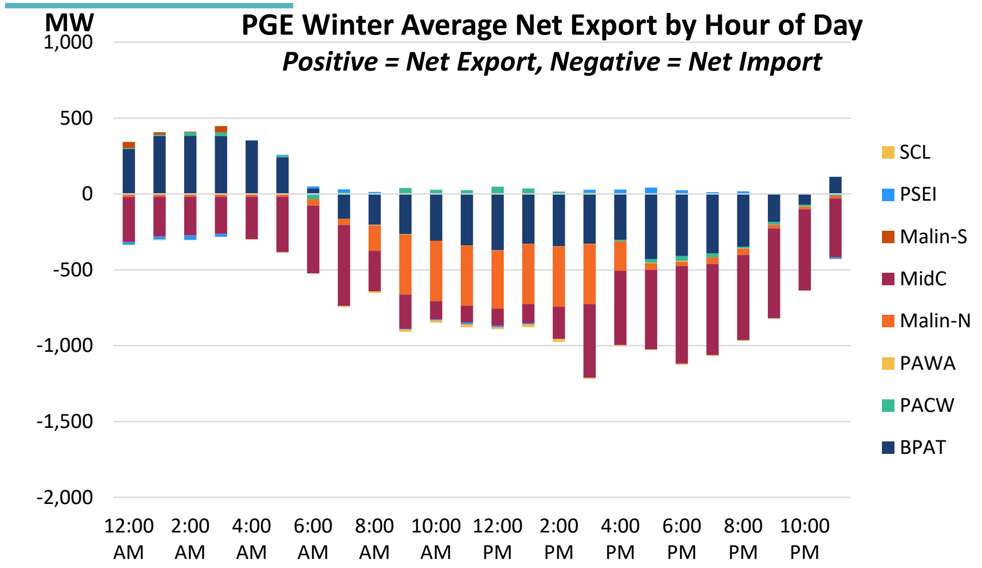


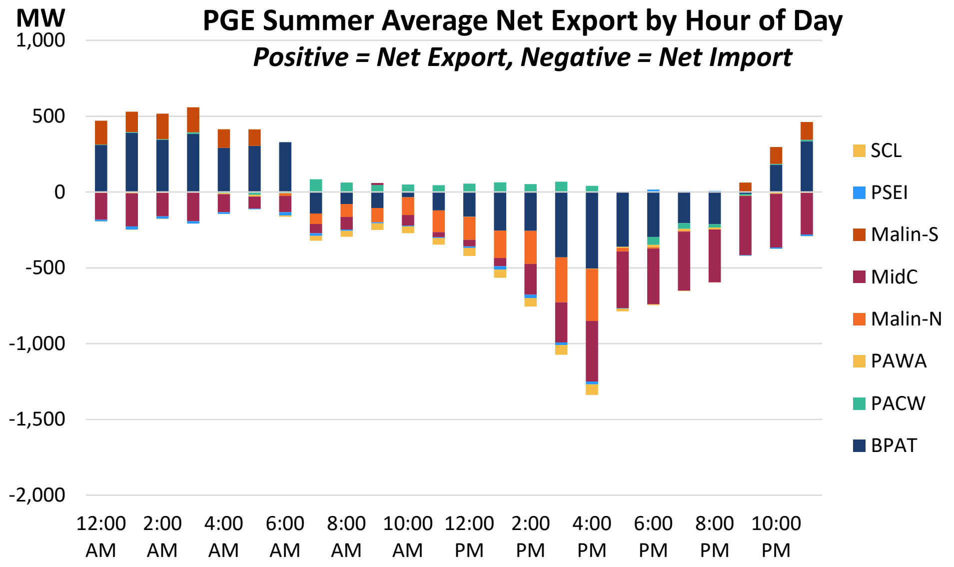


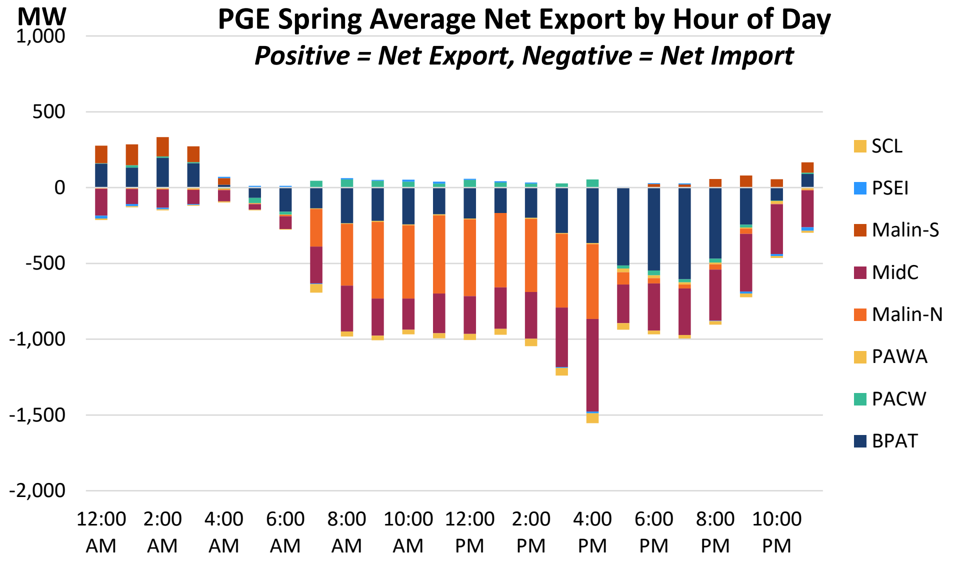


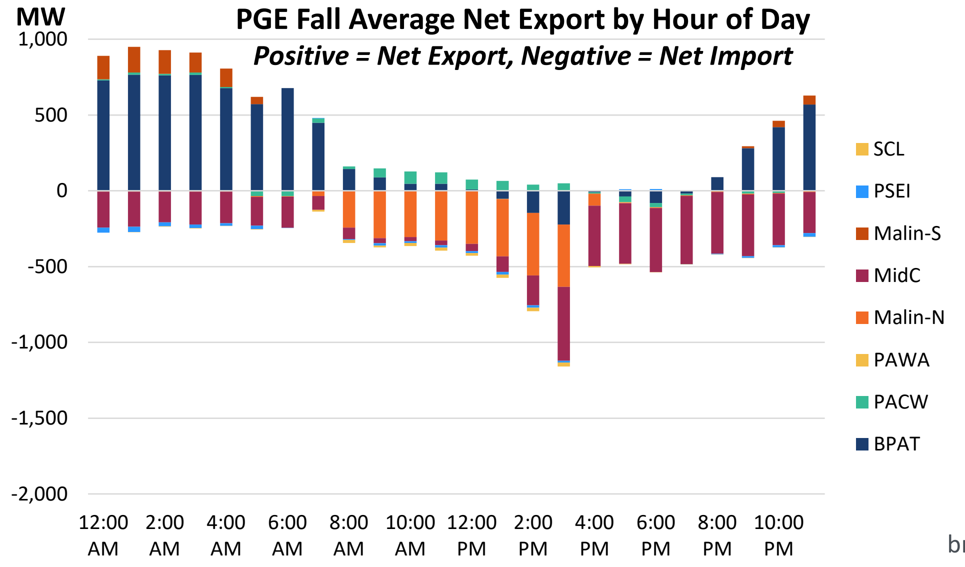
ADDITIONAL PGE RESULTS

Bookend Markets+ Case Trading (Seasonal)







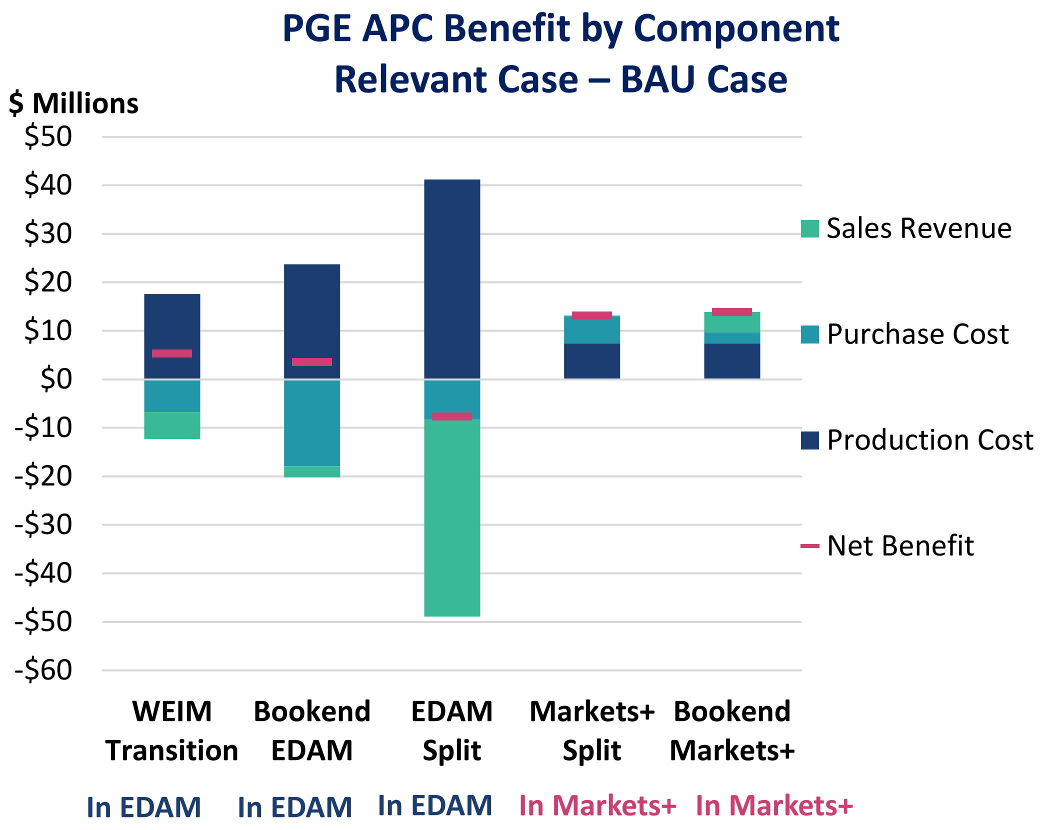


PGE Detailed APC Results

PGE Adjusted Production Cost Benefits

PGE's APC benefits are generally higher in Markets+ than in EDAM

- Though PGE tends to make more market purchases in Markets+ then EDAM, it does so at lower prices, which nets to a benefit
- PGE generally sees lower reductions in sales in Markets+ relative to BAU as well as higher sales prices, retaining most sales revenues despite the lower sales
- While EDAM sees higher displacement of production costs from internal generation compared to Markets+, due to a higher reduction in gas generation, declines in sales and average sales prices and increased purchases at average prices similar to BAU result in lower net APC benefits



PGE APCs – EDAM Bookend

PGE is seeing a net APC benefit of $3.6 million, driven by:

- **(1) Reduced generation** saving $23.8 million from 500 GWh of reduced generation, almost all of which is gas
- **(2) Benefits are offset by increased purchase costs** with average cost of purchasing increasing slightly in day ahead and purchase volumes increasing 516 GWh, resulting in a net cost of about $18 million
- **(3) Benefits are also offset by reduced sales revenues** as day-ahead average sales prices fall $2/MWh and real time sales volumes decline, a net cost about $2 million

Adjusted Production Cost Comparison for PGE

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			Status Quo	Bookend EDAM	Difference	Status Quo	Bookend EDAM	Difference	Status Quo	Bookend EDAM	Difference	
Production Cost	(+)	[1]	26,022	25,524	**-498**	$10.58	$9.85	**-$0.72**	275,234	251,476	**-$23,757**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	5,013	5,529	**516**	$26.40	$27.07	**$0.67**	132,329	149,636	**$17,307**	**(2)**
Real-Time Market		[5]	1,239	1,196	**-43**	$25.33	$26.75	**$1.42**	31,393	31,991	**$598**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,465	1,450	**-15**	$43.49	$41.40	**-$2.10**	63,730	60,021	**-$3,709**	**(3)**
Real-Time Market		[8]	1,635	1,625	**-10**	$26.26	$27.29	**$1.03**	42,934	44,343	**$1,409**	
Total Cost *(Negative Difference = Benefit)*		[9]	**29,174**	**29,174**	**0**	**$11.39**	**$11.27**	**-$0.12**	332,292	328,740	**-$3,553**	
% Change in APC											***-1.1%***	

PGE APCs – WEIM Transition

PGE is seeing a net APC benefit of $5.4 million, driven by:

- **(1) Reduced generation** saving $17.6 million from about 500 GWh of reduced generation, almost all of which is gas
- **(2) Benefits are offset by increased purchase costs** with average cost of purchasing declining in day ahead, but purchase volumes increasing 501 GWh, resulting in a net cost of about $10 million
- **(3) Benefits are also offset by reduced sales revenues** as day-ahead average sales prices increase $1/MWh in day ahead but sales volumes decline about 200 GWh

Adjusted Production Cost Comparison for PGE

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Status Quo**	**WEIM Transition**	**Difference**	**Status Quo**	**WEIM Transition**	**Difference**	**Status Quo**	**WEIM Transition**	**Difference**	
Production Cost	(+)	[1]	26,022	25,558	**-464**	$10.58	$10.08	**-$0.50**	275,234	257,613	**-$17,621**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	5,013	5,513	**501**	$26.40	$25.79	**-$0.61**	132,329	142,171	**$9,842**	**(2)**
Real-Time Market		[5]	1,239	1,077	**-162**	$25.33	$26.25	**$0.92**	31,393	28,274	**-$3,120**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,465	1,275	**-190**	$43.49	$44.60	**$1.11**	63,730	56,881	**-$6,849**	**(3)**
Real-Time Market		[8]	1,635	1,699	**64**	$26.26	$26.02	**-$0.23**	42,934	44,226	**$1,292**	
Total Cost *(Negative Difference = Benefit)*		[9]	**29,174**	**29,174**	**0**	**$11.39**	**$11.21**	**-$0.18**	332,292	326,951	**-$5,342**	
% Change in APC											*-1.6%*	

PGE APCs – EDAM Split

PGE is seeing a net APC loss of $7.7 million, driven by:

- **(1) Reduced generation** saving $41.2 million from 1,200 GWh of reduced generation, 1,100 GWh of which is gas
- **(2) Slight increase in purchase costs** with average cost of purchasing staying roughly the same in day ahead, but purchase volumes increase 457 GWh, resulting in a net cost of about $12 million
- **(3) Benefits are offset by reduced sales revenues** as day-ahead average sales prices fall $5 in day-ahead and $2 in real time, with volumes declining about 400-500 GWh in both, costing about $40 million
  - Prices decline considerably as PGE enters the solar-heavy EDAM market footprint in this case, but doesn't have the same export partners in bookend EDAM like BPAT

Adjusted Production Cost Comparison for PGE

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Status Quo**	**EDAM Split**	**Difference**	**Status Quo**	**EDAM Split**	**Difference**	**Status Quo**	**EDAM Split**	**Difference**	
Production Cost	(+)	[1]	26,022	24,786	**-1,236**	$10.58	$9.44	**-$1.14**	275,234	234,012	**-$41,222**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	5,013	5,469	**457**	$26.40	$26.38	**-$0.02**	132,329	144,302	**$11,974**	**(2)**
Real-Time Market		[5]	1,239	1,056	**-184**	$25.33	$26.30	**$0.97**	31,393	27,768	**-$3,626**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,465	1,005	**-460**	$43.49	$38.12	**-$5.38**	63,730	38,327	**-$25,403**	**(3)**
Real-Time Market		[8]	1,635	1,132	**-503**	$26.26	$24.53	**-$1.72**	42,934	27,766	**-$15,168**	
***Total Cost** (Negative Difference = Benefit)*		[9]	**29,174**	**29,174**	**0**	**$11.39**	**$11.65**	**$0.26**	332,292	339,989	**$7,696**	
% Change in APC											***2.3%***	

PGE APCs – Markets+ Split

PGE is seeing a net APC benefit of $13.2 million, driven by:

- **(1) Reduced generation** saving $7 million from 700 GWh of reduced generation, about 300 GWh of which is gas
- **(2) Reduced purchase costs** with day-ahead purchase volumes increasing 800 GWh but prices also declining almost $5/MWh as PGE buys mainly from BPA, resulting in a net cost reduction of ~$5 million
- **(3) About equal sales revenues** with day-ahead sales revenues increasing due to higher average sales prices and real-time sales revenues decreasing due to lower volumes sold

Adjusted Production Cost Comparison for PGE

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Status Quo**	**Markets+ Split**	**Difference**	**Status Quo**	**Markets+ Split**	**Difference**	**Status Quo**	**Markets+ Split**	**Difference**	
Production Cost	(+)	[1]	26,022	25,324	**-698**	$10.58	$10.58	**$0.00**	275,234	267,808	**-$7,426**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	5,013	5,835	**822**	$26.40	$21.79	**-$4.61**	132,329	127,166	**-$5,163**	**(2)**
Real-Time Market		[5]	1,239	967	**-273**	$25.33	$32.00	**$6.67**	31,393	30,929	**-$464**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,465	1,475	**10**	$43.49	$45.65	**$2.16**	63,730	67,338	**$3,608**	**(3)**
Real-Time Market		[8]	1,635	1,477	**-158**	$26.26	$26.71	**$0.45**	42,934	39,456	**-$3,478**	
Total Cost *(Negative Difference = Benefit)*		[9]	**29,174**	**29,174**	**0**	**$11.39**	**$10.94**	**-$0.45**	332,292	319,110	**-$13,182**	
% Change in APC											*-4.0%*	

PGE APCs – Markets+ Bookend

PGE is seeing a net APC benefit of $14 million, driven by:

- **(1) Reduced generation** saving $7.5 million from 500 GWh of reduced generation, about 200 GWh of which is gas
- **(2) Reduced purchase costs in the day-ahead** where average cost of purchasing declines about $3/MWh from BAU offsetting cost increases due to 613 GWh of increased sales volume, resulting in a net cost reduction of ~$2 million
- **(3) Increased day-ahead sales revenues** as average sales price increases about $2.5/MWh, which is offset by reduced real-time sales revenues of $2.8 million due to declining sales volumes

Adjusted Production Cost Comparison for PGE

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Status Quo**	**Bookend Mkt+**	**Difference**	**Status Quo**	**Bookend Mkt+**	**Difference**	**Status Quo**	**Bookend Mkt+**	**Difference**	
Production Cost	(+)	[1]	26,022	25,527	**-495**	$10.58	$10.49	**-$0.09**	275,234	267,788	**-$7,446**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	5,013	5,626	**613**	$26.40	$23.19	**-$3.21**	132,329	130,441	**-$1,888**	**(2)**
Real-Time Market		[5]	1,239	1,011	**-229**	$25.33	$30.68	**$5.35**	31,393	31,007	**-$386**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,465	1,536	**70**	$43.49	$46.06	**$2.57**	63,730	70,738	**$7,008**	**(3)**
Real-Time Market		[8]	1,635	1,454	**-181**	$26.26	$27.59	**$1.34**	42,934	40,122	**-$2,812**	
***Total Cost** (Negative Difference = Benefit)*		[9]	**29,174**	**29,174**	**0**	**$11.39**	**$10.91**	**-$0.48**	332,292	318,376	**-$13,916**	
% Change in APC											***-4.2%***	

Comparing EDAM Results Against MONET Modeled Trading

Context

As a part of our PGE EDAM benefits study, we analyzed the MONET modeling assumptions to assess if and how our simulated EDAM results can be compared with the MONET's simulated trading

Based on our review of the MONET assumptions, we have concluded that **MONET modeling captures PGE system operations and trading in a manner consistent with participation in EDAM.**

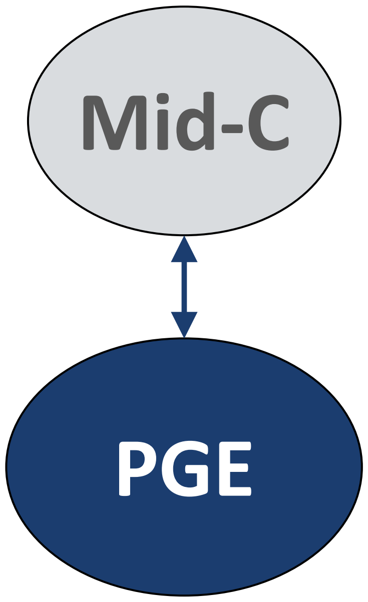
- In contrast to our modeling for the EDAM benefits study, the MONET model uses a simplified set of assumptions about PGE's system and its capability to trade with other BAAs in the WECC.
- However, those assumptions generally align with how the EDAM will function once implemented, therefore we conclude estimates of PGE's trading volumes using MONET are likely to more closely approximate PGE's trading volumes in EDAM than in the current bilateral market in the WECC.

The following slides summarize the key assumptions across MONET and our EDAM Benefits Study model and highlights the ways in which MONET models PGE in a similar manner as we model it in EDAM.

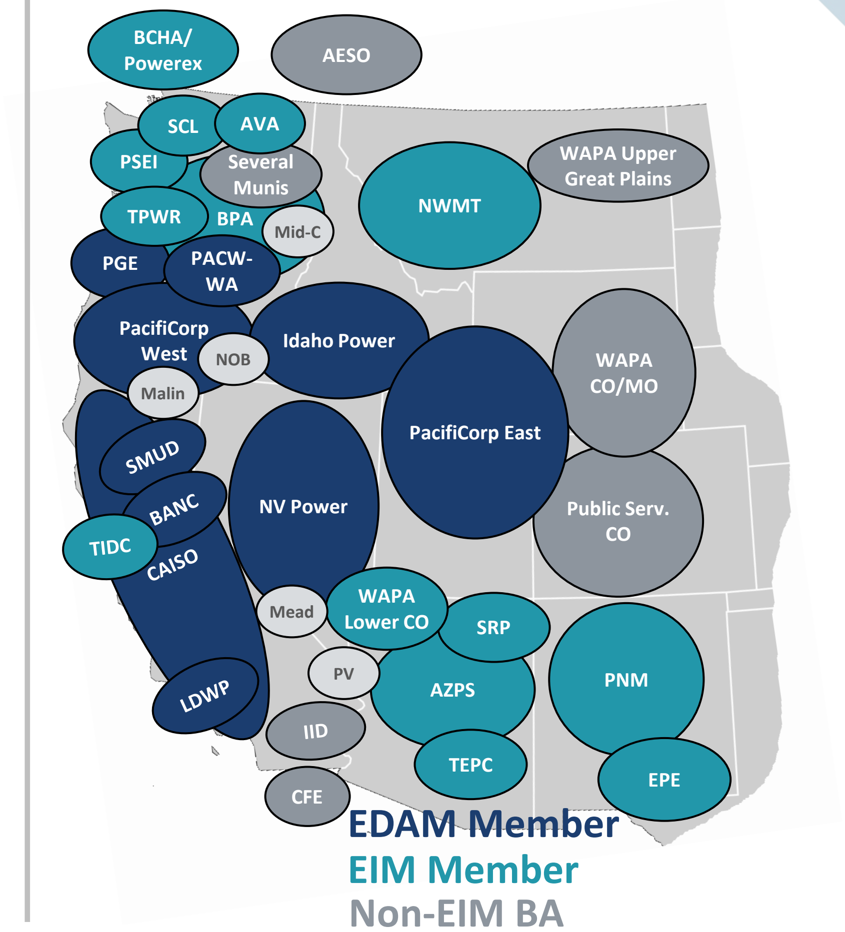
MONET vs EDAM Benefits Modeling Framework

Assumption Area	MONET Model	Brattle EDAM Model
Optimization scope	PGE system dispatch and trades to/from Mid-C	WECC-wide unit commitment and dispatch
Decision cycles	One dispatch decision cycle	Multiple cycles for DA UC, DA ED, & RT
Trading limits	Unrestricted	contractual limitations between BAAs (TTC, ETC, EIM)
Trading types	Hourly	Block & hourly bilateral, **hourly EDAM & EIM**
Wheeling fees and hurdles on trades	None	OATT rates + friction on incremental, **None for EIM / EDAM trades**
Purchase/sale prices	Monthly forwards from PGE trading, shaped to hourly by MONET team	Endogenous to model, **explicitly captures hub pricing including Mid-C**
Network constraints	None	WECC paths

PGE MONET Model Topology



EDAM Benefits Model Topology



Note: this comparison does not capture all of the details modeled in the EDAM benefits study, rather focuses on the assumptions that are relevant for assessing trading / market benefits

MONET reflects the key elements of trading in EDAM

Assumption Area	MONET Model	Brattle EDAM Model
Optimization scope	PGE system dispatch and trades to/from Mid-C	WECC-wide unit commitment and dispatch
Decision cycles	One dispatch decision cycle	Multiple cycles for DA UC, DA ED, & RT
Trading limits	Unrestricted	contractual limitations between BAAs (TTC, ETC, EIM)
Trading types	Hourly	Block & hourly bilateral, **hourly EDAM & EIM**
Wheeling fees and hurdles on trades	None	OATT rates + friction on incremental, **None for EIM / EDAM trades**
Purchase/sale prices	Monthly forwards from PGE trading, shaped to hourly by MONET team	Endogenous to model, **explicitly captures hub pricing including Mid-C**
Network constraints	None	WECC paths

Although our model is more detailed, MONET align treats purchases and sales largely how they would be treated in the EDAM, specifically:

- **Hurdle-free trading** between PGE and the market/Mid-C is consistent between MONET and EDAM
- **Hourly market transactions** allow for granular trading
- **Deep liquidity** in both EDAM and MONET
- **Exposure to market prices**
  - Though prices used in MONET today reflect bilateral market, that could updated when EDAM goes live
- **Capability for large trading volumes**
  - Trading volumes and network constraints are completely unrestricted in MONET, while EDAM trades will be limited to contributed transmission and system congestion. Implying that MONET *overstates* the trading volumes that will occur in EDAM

MONET's Trading Results are Likely Consistent with EDAM, but it Fails to Capture Certain EDAM Revenues

MONET's modeling framework likely captures much of PGE's benefits from EDAM participation, and may actually overstate the benefits

- The trading volumes estimated by MONET, would be reflected in our EDAM model and captured in our Adjusted Production Cost (APC) metric.

However, MONET's simplified representation of the system leaves out some revenues PGE will collects as an EDAM member

- **Congestion revenues**: MONET does not have any transmission/trading limitations and so does not capture congestion and congestion revenues that would accrue to PGE in EDAM
- **EDAM transfer revenues & wheeling revenue impacts**: MONET captures total trade value (bilateral + EDAM) and so does not allow EDAM trade revenues and loss of wheeling revenue on bilateral trades to be directly calculated

Portland General Electric Day-Ahead Market Benefits Studies

MODELING APPROACH

PRESENTED BY
JOHN TSOUKALIS
KAI VAN HORN
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PRESENTED FOR

PGE

FEBRUARY 2024

Brattle

Table of Contents

Model Overview

Scope of Studies

Scope: to simulate the specific EDAM/M+ designs for realistic market footprints, not a simplified representation of a wholesale market across the entire WECC

- **Calculate a multiple benefit metrics:** (1) Adjusted Production Cost (APC), (2) impact on wheeling revenue, (3) loss of bilateral trading profits, and (4) EDAM/M+ congestion and transfer revenues
- **Model the EDAM and/or M+ GHG structure:** as specified in the design or contemplated design
  - EDAM: simulated the "GHG Reference Pass" to set limits on transfers into the GHG region (CA and WA).
  - M+: simulated "Resource Owner, Merit Order w/ Enhanced Floating Surplus" approach to setting transfer limits into GHG regions
  - Modeled resource-type-specific GHG costs
- **Simulate existing & prospective real-time markets:** WEIM in parallel with the EDAM, formation of a day-ahead and real-time market with M+, nodal representation of entire WECC
  - Estimated the impact on existing WEIM and new EDAM or Markets+ trades and congestion revenues
- **Capture value of coupled day-ahead and real-time markets to manage unexpected imbalance:** modeled renewable and load forecast uncertainty between DA and RT
- **Realistically represent bilateral markets:** captured existing contract-path transmission rights, major trading hubs, block trading, CAISO intertie trades, hourly BA-to-BA trades, and wheeling charges where applicable

Key Model Features

We conducted all study simulations using a **nodal production cost model of the WECC** with added market functionality, such as contract-path transmission.

- Model developed in PSO/Enelytix, which contains state-of-the-art features
  - Simultaneously optimizes contract path and physical constraints
  - Models bilateral, day-ahead, and real-time markets sequentially through multiple solution cycles
  - Co-optimizes storage resources with other resources in unit-commitment and dispatch
  - Detailed ancillary service and operating reserve modeling and co-optimization of ancillary services with energy
- **The study year is 2032**, which aims to reflect the first decade of markets operations, representing both an intermediate year in the near-future and a year with reasonably high renewable penetration in the WECC
- **Model includes two extreme weather events** based on a historic cold snap and a historic heat wave
  - These events are modeled as single weeks in which we increase modeled loads (peak and energy) and gas prices beyond the typical weather-normalized values to reflect the increased strain on the system and the ramifications of markets for addressing such strain.
  - Capturing non-weather-normal impacts is becoming increasingly important due to the increasing frequency of severe weather events
- **Modeled hydro represents average hydro year in the WECC,** using data from 2009 for hydro generation
- **Study base cases include the existing WEIM and WEIS markets**, meaning all noted cost and benefit metrics already include an entity's benefit coming from WEIM and WEIS (and thus all results show incremental loss or gain in WEIM and WEIS benefits as a day-ahead market is formed)

See Appendix for additional model and assumptions detail, including detail related to EDAM and M+ design modeling

Estimated EDAM & M+ Benefits are Conservatively Low

The estimated benefits are likely understated due to several factors:

- **Overstated base-case efficiency:** our simulation of the BAU is more efficient than reality
  - The Base Case assumes that balancing authorities have optimal security-constrained unit-commitment and dispatch (SCUC and SCED) in both DA and RT, making the simulated dispatch more optimal than in reality.
  - Inefficient utilization of transmission by bilateral trades is not fully modeled, understating the extent EDAM and M+ will be able to make better use of all physically and contractually available transmission.
  - Transmission outages are not modeled, which would magnify the benefit of SCED-based congestion management in EDAM and M+ compared to the BAU
- **Normalized loads and fuel prices:** the model uses weather-normalized loads and averaged monthly natural gas prices without daily volatility
  - Challenging market conditions (beyond the included heat wave and cold snap), such during as the 2022 gas price spikes, will magnify EDAM/M+ benefits. Illustrated by the WEIM experience of much higher benefits in 3Q of 2021 and 3Q-4Q of 2022
  - The Base Case does not reflect the limited liquidity of bilateral market during challenging market conditions
- **No capacity benefits quantified:** we have not quantified the extent to which EDAM and M+ may reduce investment costs associated with lower operating reserve requirements

Model Details

Overview of Modeling Approach

We utilize the WECC ADS nodal production cost model as a starting point imported into Power System Optimizer (PSO), as refined during the EDAM feasibility study and follow-on engagements

Utilized the Polaris Power System Optimizer (PSO), an advanced market simulation model

- Nodal mixed-integer model representing each load and generator bus in the WECC
- Licensed through Enelytix
- Detailed operating reserve and ancillary service product definition
- Detailed representation of the transmission system (both physical power flow
- Sub-hourly granularity (but used hourly simulations due to limited data availability)
- Designed for multiple commitment and dispatch cycles (e.g., DA and RT) with different levels of foresight
- EDAM feasibility study assumptions updated to reflect the most recent utility resource plans and forecasts of system conditions and costs

PSO is uniquely suited to simulate bilateral trading, joint dispatch, imbalance markets, and RTOs, reflecting multiple stages of system operator decision making

Multi-Functional Simulation of WECC

Markets/RTO Functions & Configurations

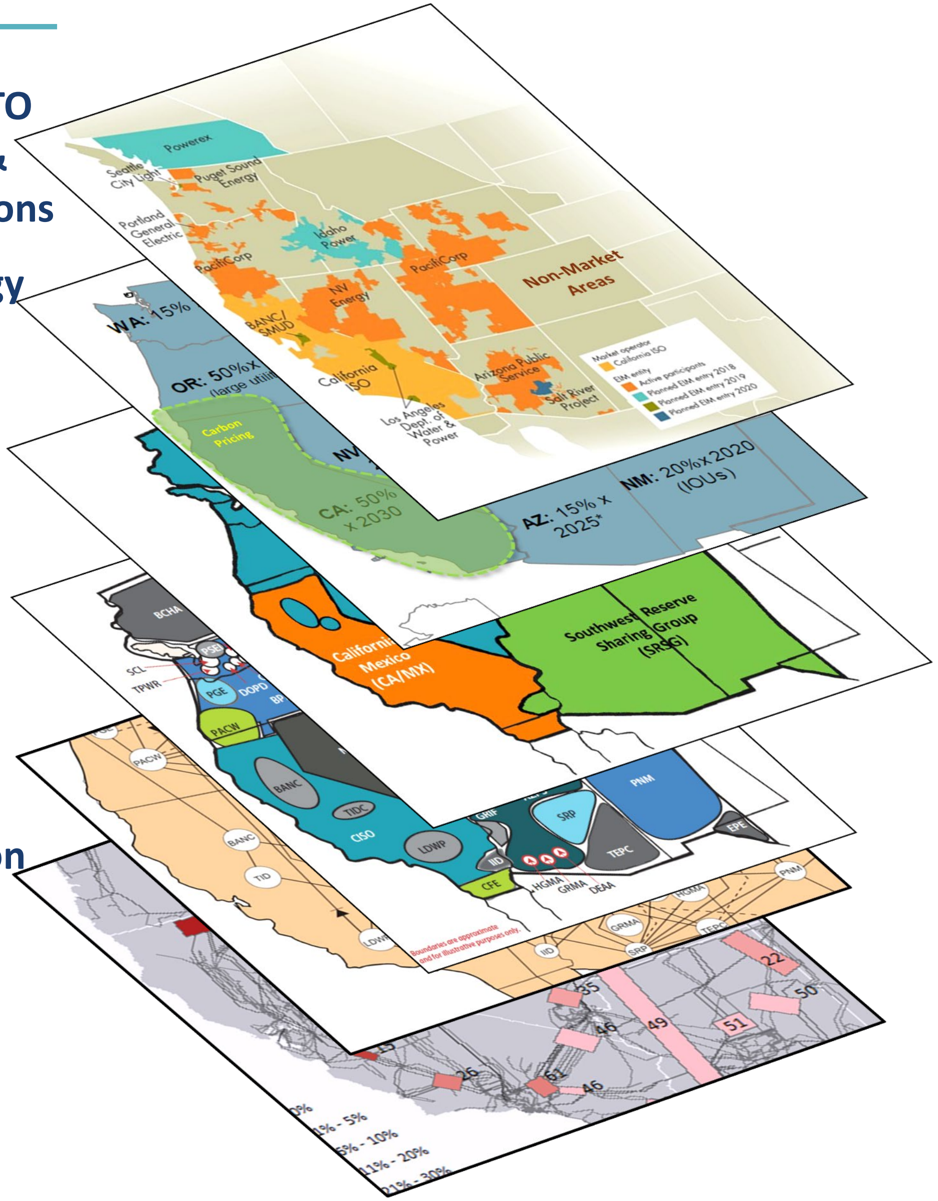
Clean Energy Policies

Reserve Sharing

BAA Functions

Bilateral Contract Paths and Transmission Rights

Physical Flows and Constraints



We employ a multi-layer simulations to represent the various physical, policy, and operational facets of the WECC

- Physical grid with ~20k buses, ~25k lines and ~5k generators represented as DC power flow
- 38 Balancing Authority Areas (BAAs) and contract paths
- The WECC reserve sharing groups
- Diverse state clean energy policies
- Major trading hubs (e.g., Mid-C, Malin, PV)
- Bilateral transmission rights
- Renewable diversity, day-ahead forecast uncertainty, real-time operations
- CAISO, RTO West, M+, EDAM, WEIM, & WEIS footprints

Independent Simulation of Multiple Time Horizons

We simulate multiple independent decision cycles to capture day-ahead vs. real-time unit commitment and dispatch and uncertainty

D-1 (am)	D-1 (~noon)	D-1 (pm-D)	D
DA Bilateral Markets	**Day-Ahead Market**	**Intra-Day Markets**	**EIM (RT Balancing)**
• DA block trades on long-term transmission rights and incremental transmission	• CAISO, EDAM, and RTO market clearing • Hourly intertie trading • Hourly trading with long-term transmission rights	• Hourly bilateral trades on remaining transmission	• EIM/CAISO trading of economic energy • Transmission released for EIM • RT balancing in BAAs

Independent real-time decision cycle used to simulate EIM functions

DA Unit Commitment Cycle → **DA Economic Dispatch Cycle** → **Real Time Cycle**

Decision cycles capture bilateral trading, market clearing, BAA functions in DA and RT, and market cycles (incl. EDAM "GHG reference" pass, EDAM market, and EIM)

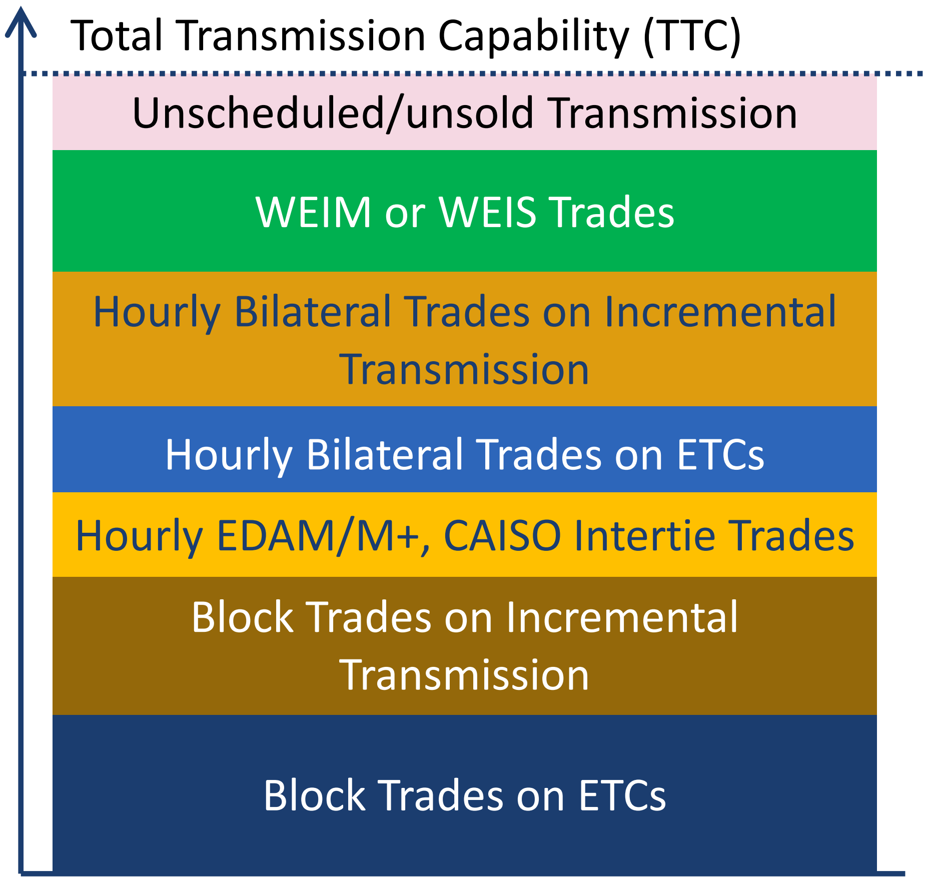
Independent real-time decision cycle used to simulate DA vs. RT, including forecast errors for wind and solar

Types of Trades and Transmission Reservations Modelled

Our model simulates the use of different types of contract-path transmission reservations for bilateral trading across DA and RT

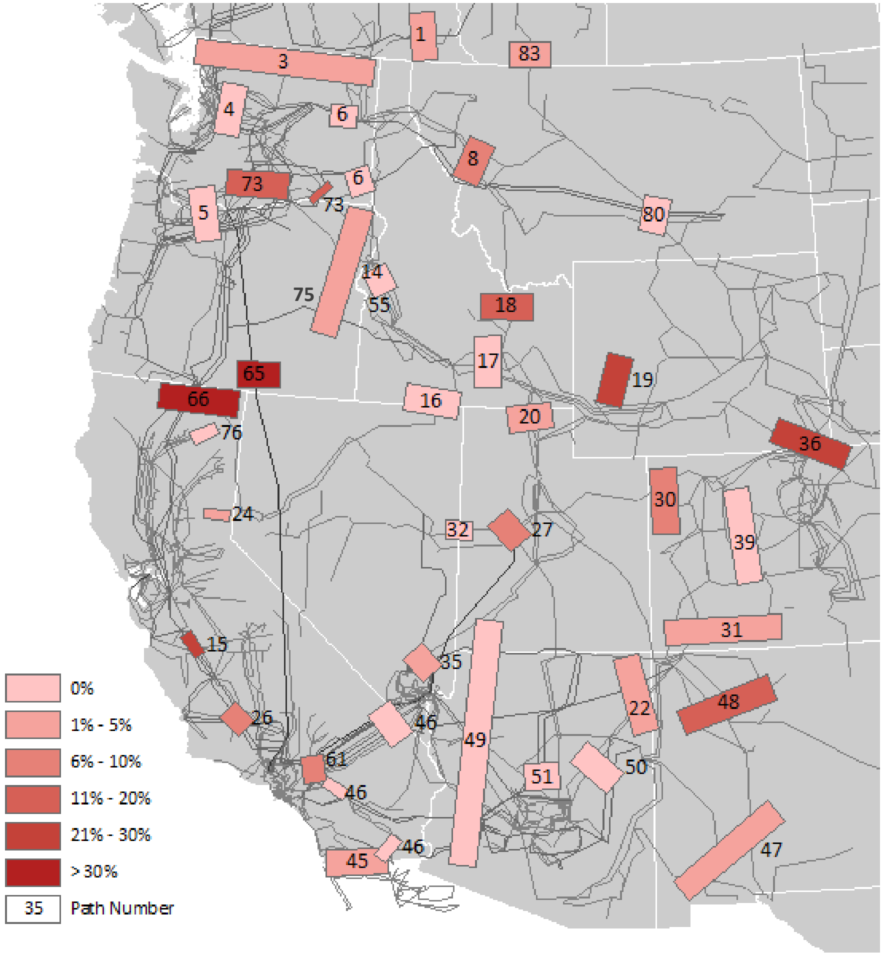
- Existing long-term transmission contracts (ETCs) and incrementally purchased transmission
- Total reservations on each contract path is limited by the total transfer capability (TTC)
- Trades are structured as blocks or hourly
- Bilateral trades between BAs, at major hubs, or across CAISO or RTO West interties
- Account for renewable diversity and day-ahead forecast uncertainty vs. real-time operations
- Unscheduled transfer capability released for EIM trades in real-time

Types of Trades Modeled



Nodal Simulations Based on Physical Transmission

WECC-Defined Paths Modeled



Limits on the physical transmission system include all the paths defined in WECC Path Rating Catalogue

- Additional transmission paths to represent congestion internal to each BA
- Limits on all paths and constraints reflect updates provided by the study participants

ENELYTIX®
powered by PSO

Power System Optimizer (PSO), developed by Polaris Systems Optimization, Inc. is a state-of-the-art market and production cost modeling tool that simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal representation of the transmission system, similar to actual RTO and ISO market operations. Such nodal market modeling is a commonly used method for assessing the operational benefits of wholesale market reforms (e.g., JDAs, EIMs, RTOs).

PSO can be used to test system operations under varying assumptions, including but not limited to: generation and transmission additions or retirements, de-pancaked transmission and scheduling charges, changes in fuel costs, novel environmental and clean energy regulations, alternative reliability criteria, and jointly-optimized generating unit commitment and dispatch. PSO can report hourly or sub-hourly energy prices at every bus, generation output for each unit, flows over all transmission facilities, and regional ancillary service prices, among other results. Comparing these results among multiple modeled scenarios reveals the impacts of the study assumptions on the relevant operational metrics (e.g. power production, emissions, fuel consumption, or production costs). Results can be aggregated on a unit, state, utility, or regional level.

PSO has important advantages over traditional production cost models, which are designed primarily to model dispatchable thermal generation and to focus on wholesale energy markets only. The model can capture the effects of increasing system variability due to large penetrations of non-dispatchable, intermittent renewable resources on thermal unit commitment, dispatch, and deployment of operating reserves. PSO simultaneously optimizes energy and multiple ancillary services markets on an hourly or sub-hourly timeframe.

Like other production cost models, PSO is designed to mimic ISO operations: it commits and dispatches individual generating units to meet load and other system requirements, subject to various operational and transmission constraints. The model is a mixed-integer program minimizing system-wide operating costs given a set of assumptions on system conditions (e.g., load, fuel prices, transmission availability, etc.). Unlike some production cost models, PSO simulates trading between balancing areas based on contract-path transmission rights to create a more realistic and accurate representation of actual trading opportunities and transactions costs. This feature is especially important for modeling non-RTO regions.

One of PSO's distinguishing features is its ability to evaluate system operations at different decision points, represented as "cycles," which occur at different times ahead of the operating hour and with different amounts of information about system conditions available. Under this sequential decision-making structure, PSO can simulate initial cycles to optimize unit commitment, calculate losses, and solve for day-ahead unit dispatch targets. Subsequent cycles can refine unit commitment decisions for fast-start resources and re-optimize unit dispatch based on the parameters of real-time energy imbalance markets. The market structure can be built into sequential cycles in the model to represent actual system operation for utilities that conduct utility-specific unit commitment in the day-ahead period but participate in real-time energy imbalance markets that allow for re-optimization of dispatch and some limited re-optimization of unit commitment. For example, PSO can simulate an initial cycle that determines day-ahead unit commitment decisions that reflects the constraints faced by, and decisions made by, individual utilities when committing their resources in the day-ahead timeframe. The initial day-ahead commitment cycle is followed by cycles that simulate day-ahead economic dispatch, including bilateral trading of power, and a real-time economic dispatch, reflecting trades in real time (whether bilateral or optimized through an EIM or RTO). Explicit commitment and dispatch cycle modeling allows more accurate representation of individual utility preference to commit local resources for reliability, but share the provision of energy around a given commitment.

Simulating Several Wholesale Market Cycles in PSO

The model setup for wholesale market simulation effort contains several cycles to simulate unit commitment and dispatch decisions in three different timeframes and within different market structures. For example, cycles simulated can include are:

- **Day-Ahead Unit Commitment Cycle:** the model optimizes unit commitment decisions, 24 hours at a time (with 48-hour look ahead), for long-lead time resources such as coal and nuclear plants, based on their relative economics and operating characteristics (e.g., minimum run time, maintenance schedules, etc.), transmission constraints, and trading frictions. The model ensures that enough resources are committed to serve forecasted load, accounting for average transmission losses and the need for ancillary services. Separate regions' commitment decisions are segregated through higher hurdle rates on imports and exports. Trading within a single balancing area, like the various RTO sub-zones, is not subject to any hurdles.
- **Day-Ahead Economic Dispatch Cycle:** the model solves for the optimal level of hourly day-ahead dispatch and trading in 24-hour forward-looking optimization cycles, with 48-hour look ahead periods. Dispatch across the study footprint is optimized based on resource economics. In this cycle, the model also co-optimizes ancillary service procurement for each area. The high hurdle rates for unit commitment are lowered to enable more bilateral trading between balancing areas.
- **Intra-day trading:** the model simulates market activity through one-hour optimization horizons. Trading is assumed to utilize unused transmission, represented as the difference between their day-ahead trading volume and the total contract path limits. No unit re-commitment is allowed due to the non-firm nature of the transactions. Changes to generation availability, such as forced outages, which were not "visible" during the day-ahead cycle become visible during this cycle.
- **Real-Time Cycle:** this cycle simulated the operation of the real-time imbalance markets, such as through EIM transactions. In this cycle, the model can re-optimize dispatch levels and unit commitment decisions for fast-start thermal resources (based on the assumption that the real-time market design allows for unit re-commitment). Deviations from day-ahead forecasts (due to uncertainty) need to be balanced in real-time.

These cycles can take on different assumptions, depending on market structure. In a bilateral setting, all are set up to analyze utility-specific unit commitment and dispatch decisions, with each of them including hurdle rates and transmission fees that limit the amount of economic transactions that can take place between the utilities. In EIM and EDAM+EIM scenarios, all of the cycles are set up to simulate market-wide optimization of unit commitment and dispatch, including the EDAM "reference pass" cycle. In the EDAM case, there would be no hurdle rates between EDAM participants in any of the cycles, allowing the model to optimize both unit commitment and dispatch in the market footprint on both a day-ahead and real-time basis.

Benefits Metrics

Benefit Metric: Adjusted Production Cost

Adjusted Production Cost (APC) is a standard metric used to capture the direct variable energy-related costs from a customer impact perspective

The APC is calculated for the BAU Case and the RTO case to determine the RTO-related reduction in APC

- By using the generation price of the exporter and load price of the importer for sales revenues and purchase costs, the APC metric does not capture wheeling revenues and the remaining portion of the value of the trade to the counterparties (see next slide)

The APC is the sum of production costs and purchased power less off-system sales revenue:

(+) Production costs (fuel, startup, variable O&M, emissions costs) for generation owned or contracted by the load-serving entities

(+) Cost of bilateral and market purchases valued at the BAA's load-weighted energy price ("Load LMP")

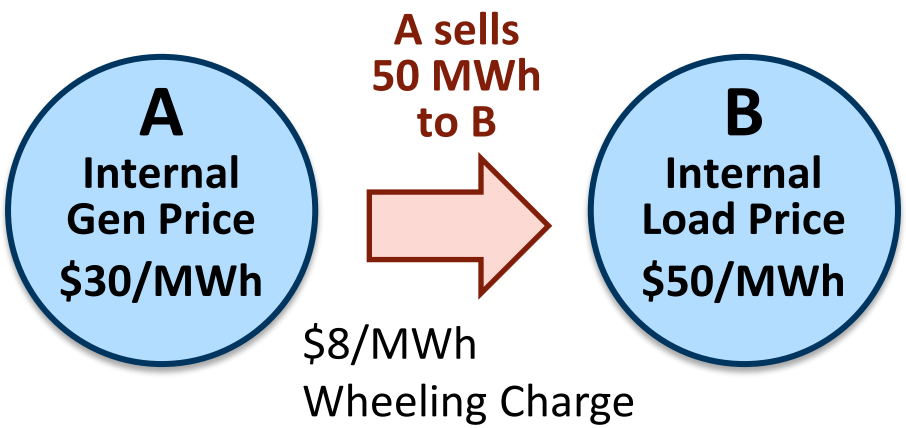
(−) Revenues from bilateral and market sales valued at the BAA's generation-weighted energy price ("Gen LMP")

Benefit Metrics: Wheeling Revenues, Trading Gains

Based on the simulation results, we also estimate several additional impacts from increased trading facilitated by the market reforms, which is not fully captured in APC.

- **Wheeling Revenues:** collected by the exporting BAAs based on OATT rates
- **Trading Gains:** buyer and seller split 50/50 the trading margin (and congestion revenues in EIM/EDAM)

EXAMPLE: Bilateral Trade



The <u>APC metric</u> only uses area-internal prices for purchase cost and sales revenues, which does not capture part of the value:

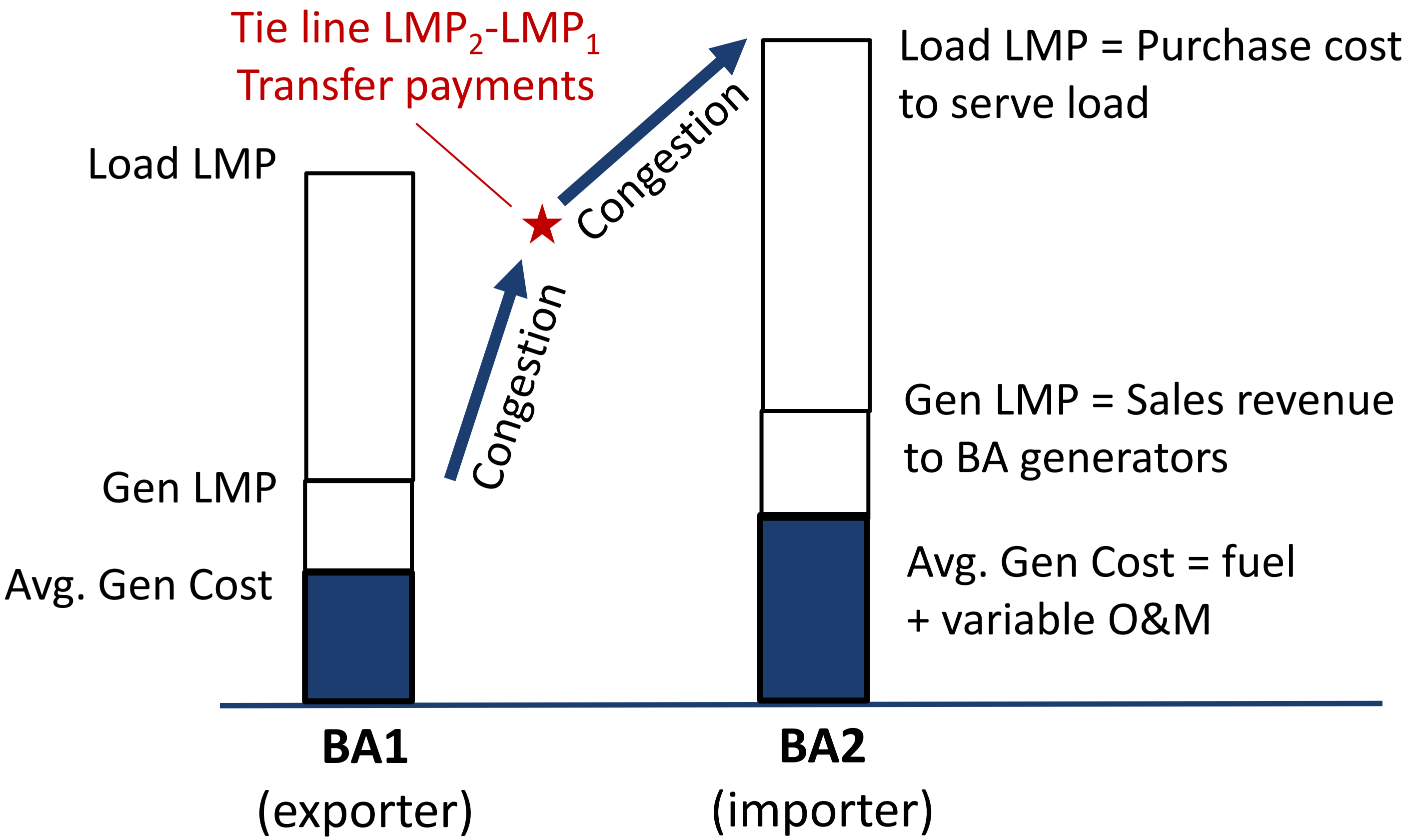
- A receives $30×50MWh=$1,500 in APC sales revenues
- B pays $50×50MWh=$2,500 in APC purchase costs

➔ $1,000 of trading value not captured in APC metric

Trading value = $20/MWh Δprice x 50 MWh = $1000

- Exporter A receives wheeling revenues: $8/MWh x 50MWh = $400
- Remaining $600 trading gain split 50/50: both A and B receive $300

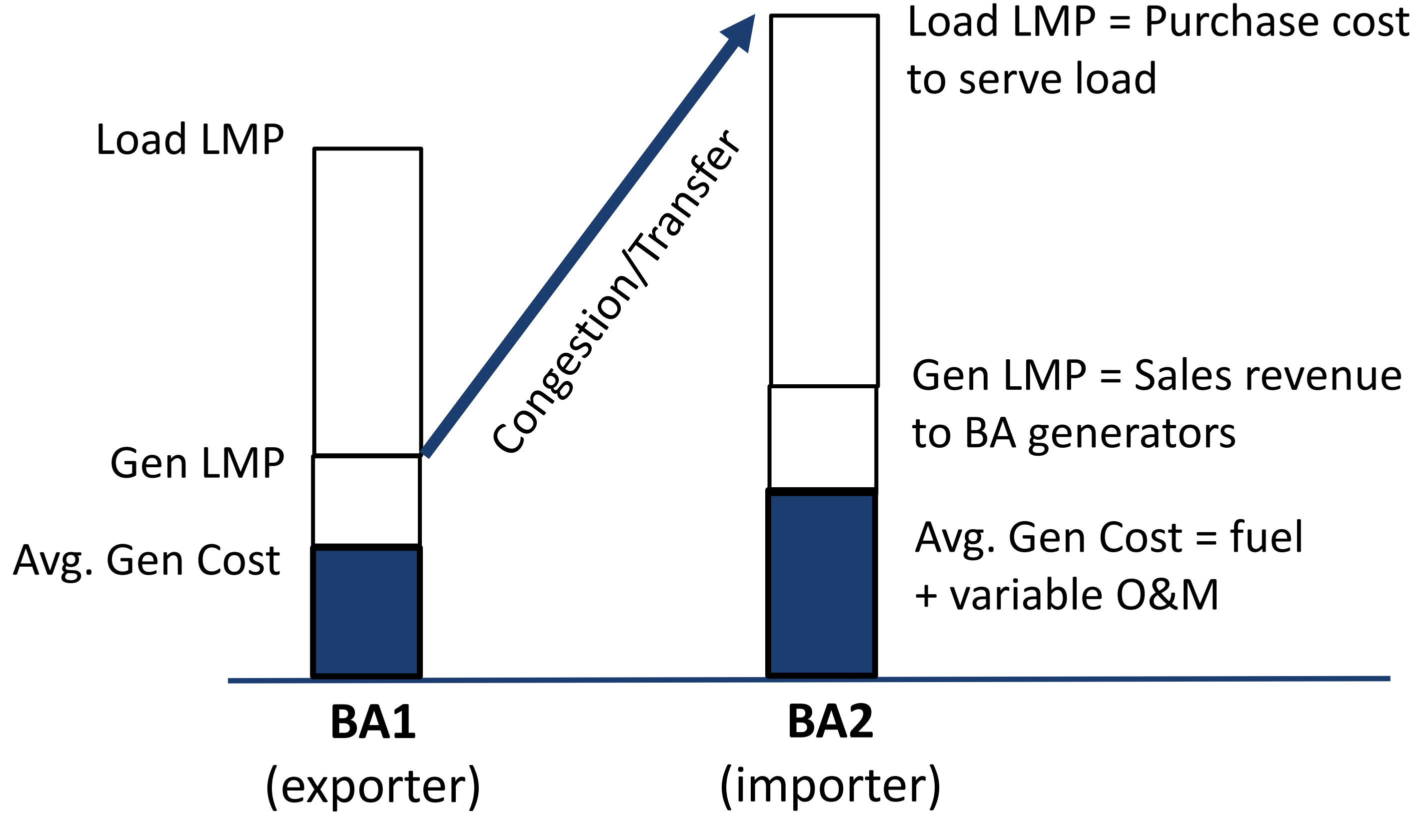
Illustration of EDAM Congestion and Transfer Revenues



EDAM congestion and transfer revenues estimated based on individual tie line LMPs:

- **Congestion Payment (to exporter)**
  = MW x (Tie LMP_1 – Gen LMP_1)
- **Congestion Payment (to importer)**
  = MW x (Load LMP_2 – Tie LMP_2)
- **Transfer Payment (split 50/50)**
  = MW x (Tie LMP_2 – Tie LMP_1)

Illustration of M+ Congestion/Transfer Revenues



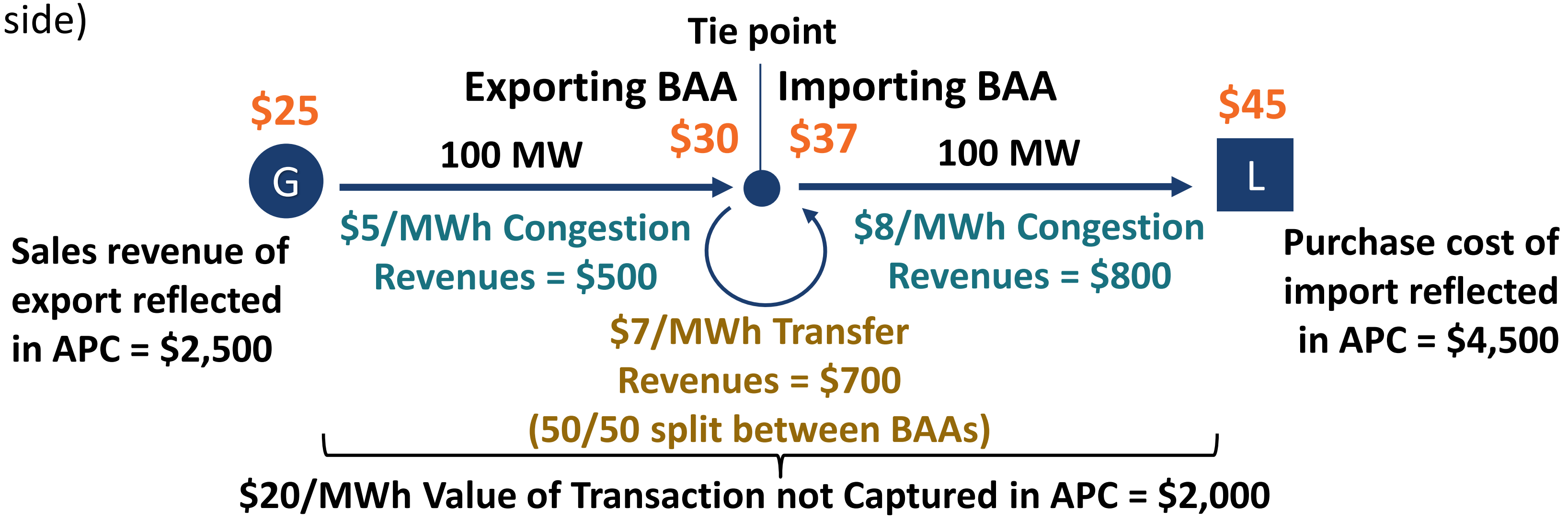
M+ congestion/transfer revenues rolled together and estimated based on BA load and gen LMPs:

- **Congestion/Transfer Revenue Payment (split 50/50) = MW x (Load LMP_2 – Gen LMP_1)**

Illustration of Congestion/Transfer Revenues vs. APC

Generators and loads get paid/pay the prices within their BAAs

- Therefore, congestion on internal transfers (between a member's own gen and load) is captured in the APC metric.
- However, congestion/transfer revenue on external transactions (to neighboring members) is not captured in APC.
- In the example below, for an external market transaction, the selling BAA has a price of $25 and the purchasing BAA has a price of $45.
  - The $20 difference between the seller and buyer is the congestion and transfer revenue.
  - **$5/MWh of congestion revenue** is allocated to the seller ($30 on their side of the intertie less $25 internal gen price)
  - **$8/MWh of congestion revenue** is allocated to the buyer ($45 internal load price less $37 on their side of the intertie)
  - **$7/MWh of transfer revenue** is split 50/50 between the buyer and seller ($37 on the buyer side of the intertie less $30 on the seller side)



EDAM Modeling Assumptions

Resource Sufficiency & Transmission

Resource Sufficiency Test

- The EDAM design applies the Resource Sufficiency Test to each EDAM member the day prior to real-time, before day-ahead market operations
  - In the 2019 EDAM Feasibility Study, E3 conducted an hourly analysis of Resource Sufficiency for each proposed EDAM member at that time
    - In that analysis, failure of the test was extremely rare
    - In fact, all current study participants (BANC, CAISO, IPCO, LADWP, SMUD, and PAC) previously passed the resource sufficiency test in all hours
  - For this study, conducted ex-post check and confirmed that all assumed EDAM members are resource sufficient in all hours

EDAM Transmission

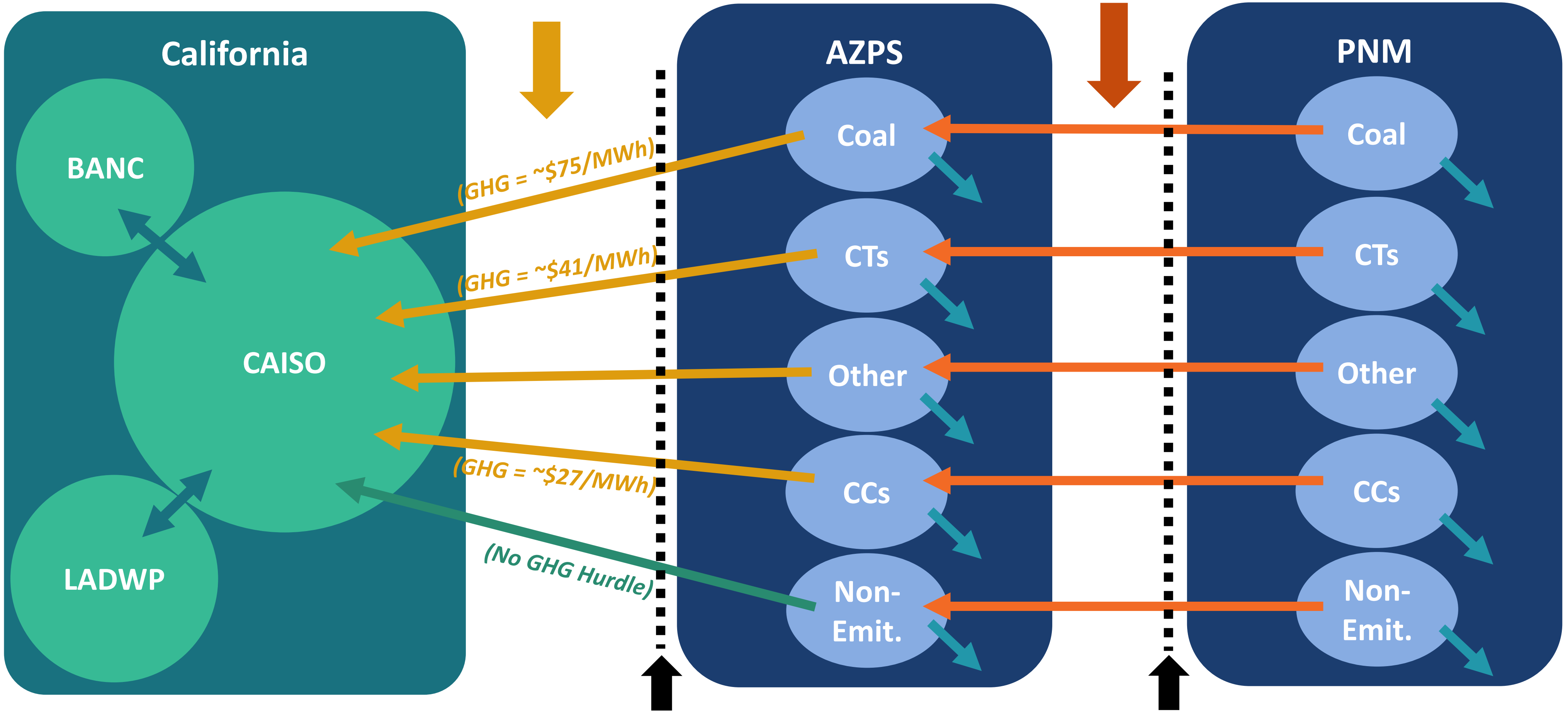
- All three buckets of EDAM transmission are modeled and assumed to be hurdle-free:
  - Bucket 1: Transmission to Support Resource Sufficiency
    - Includes existing long-term transmission contracts (“ETCs”) for energy used for sufficiency accounting purposes
  - Bucket 2: “Donated” Transmission Contracts
    - Existing transmission contracts (ETCs) made available (“donated”) to the EDAM by participants
  - Bucket 3: Unsold Firm Transmission
    - Remaining transmission made available for EDAM (participants might hold back from transmission for block trading)
- Simulated Bucket 1 and 2 EDAM transmission equals total ETC capacity; Bucket 3 transmission equals the remaining transfer capability (i.e., TTC less ETC) between the assumed EDAM members

GHG Structure Illustration

Sales incur unit GHG cost, relevant hurdles, and are limited by attributions from the GHG Reference Pass

Resources can sell into neighboring BAAs by paying applicable fees:

- Bilateral market: OATT fee, trading margin
- EIM: no hurdle on available transmission
- EDAM: no hurdle on Buckets 1,2, & 3



Resources serve load in their own BAA with no hurdle

Flows restricted to BAA export limit
+ BAA Net Export GHG Attribution Limit

A nomogram restricting total BAA-to-BAA flows to export limit, which varies by market type – bilateral, EIM, and EDAM

EDAM GHG Structure: "Reference Cycle"

Our GHG modeling structure accounts for two constraints specified in the EDAM design for GHG attributions relative to a baseline from EDAM's "reference pass" cycle, which we simulate as well

1. **Resource Specific GHG Attribution (resource-type attribution under proposed approach) =**

max{0, min{GHG Bid, UEL – Reference Pass, Optimal Dispatch}}

Simulations assume resources bid all their capacity into the GHG Region

Calculated using results of our GHG Reference Pass run

GHG attribution cannot exceed final dispatch of resource

2. **BAA Total GHG Attribution <= (Net TTC Difference - BAA Net Exports hourly in reference pass)**

These reference pass results set **hourly export limits** that are enforced in the actual EDAM case for EIM and EDAM members for sales to GHG balancing authorities

Imbalance Reserve Requirement

EDAM reserve requirement estimated to fall about 2-4.2 GWh in the EDAM Case (relative to Base Case) due to the diversity benefit achieved by the EDAM footprint

Imbalance Reserve is a new reserve product being implemented by the CAISO as part of their DA Market Enhancements (DAME) initiative, and will apply to EDAM

- The Imbalance Reserve requirement (up and down) will be set to meet the 97.5 percentile of each BAAs historical net load variability
- In EDAM, participants' Imbalance Reserve Requirement will be reduced by the diversity benefit created by pooling commitment and dispatch across the regional footprint
- Does not impact other operating reserve types – regulation, contingency, etc.
- **Brattle Assumption:** we calculated each EDAM participants Imbalance Reserve Requirement and the EDAM diversity benefit to reduce each member's requirement

Markets+ Assumptions

Transmission Usage in the Market

Modeling Assumption: All transmission with other Markets+ entities was modeled as available for market transaction without any wheeling charges

- Brattle modeled BPAT consistent with their participation in WEIM, with limited transmission made available to the market
- We asked all study participants if you want to identify some transmission to set aside for WRAP, third party ownership, or other reasons.
  - *No study participants identified any WRAP transmission to be withheld from the market optimization*

M+ GHG Structure

Based on our review of the draft tariff language and the task force materials posted online, we assume for the purposes of these studies that M+ will use the following approach:

- Only energy identified as GHG surplus will be available to transfer to the GHG zone
- GHG surplus identification will happen through the Resource Operator and Merit Order approach
  - Rules from state agencies may restrict what resources can be identified as surplus energy by the resource operator
  - Resource operators make all resources available for transfer to the GHG zone
  - BA-level hourly surplus capacity available for transfer to the GHG transfer is calculated outside of the model using modeled load and a merit order constructed from modeled cost and capacity assumptions
  - We apply type-specific GHG costs to surplus transfers to the GHG zone
- We assume the market optimization will use the “Enhanced Floating Surplus” approach
  - This allows transfer of type-specific surpluses from anywhere in the dispatch range of eligible resource

Seams Management

Modeling Assumption: Brattle modeled the Markets+ seam consistent with the description from the Seams Task Force

- Exports into or imports out of Markets+ were charged a small bilateral friction charge plus the exporting entity's wheeling rate
- This is consistent with how we model the CAISO seam in the BAU Case
- Exports across the Markets+ seam into a GHG zone are charged an unspecified resource GHG cost (equivalent to the emissions charge for a generic gas-CC unit)
  - This makes Markets+ exports to CAISO and other GHG entities fairly expensive, as the GHG cost alone will be around $30/MWh

Modeled Trading Friction Charges ($/MWh)

Transaction Type	BAU Case	Markets+ Case	Pays OATT?
EIM & WEIS Transactions	$0	$0	No
Bilateral Transactions	$6	$6	Yes
ETC Transactions	$6	$6	No
RTO Intertie Transactions	$1.5	$1.5	Yes*
Block Transactions	$1.5	$1.5	Yes*
EDAM Transactions	$0	$0	No
Markets+ Transactions	$0	$0	No

*Note: *Block and RTO transactions won't pay an OATT rate if the transaction occurs over long-term ETC rights, just like ETC transactions broadly. The friction charge is the same regardless.*

Markets+ imports & exports pay either the bilateral or RTO intertie friction costs *(RTO for trades with CAISO or SPP West, who connects to PACE)*

Real Time Market

Brattle modeled Markets+ with a real-time market that operates like SPP's Western Energy Imbalance Service (WEIS)

- At the time the study was conducted, the Markets+ Task Forces had not discussed how the real-time market would function, but it is expected that Markets+ would include a RT market
- This also provides an apples-to-apples comparison with EDAM/WEIM

Real-time transactions at the Markets+ seam pay a small hurdle rate to capture bilateral friction + the exporting BAA's wheeling free + applicable GHG costs

- Transactions in real time across GHG zones and between markets (e.g., from EDAM to Markets+ or from Markets+ to CAISO/EDAM are charged the unspecified GHG rate)
  - For example, exports from **CAISO to Markets+** are charged the CAISO TAC + hurdle rate
  - Exports from **Markets+ to CAISO** are charged the GHG rate + exporter's OATT rate + hurdle rate

Congestion Rent Allocation

Congestion revenues are allocated back to market participants consistent with proposed constraint-level approach

- The Markets+ proposed approach is to allocate congestion based on the portion of rights each market participant owns on the constraint where congestion is collected
- *This differs from the EDAM model where tie points were used between BAs to determine the allocation of revenue between two BAs, splitting revenue into internal congestion revenue within a BA (kept by that BA), and transfer revenue between two BAs (split 50/50 between the BAs)*

Market Transmission Use Settlement

Assumption: Brattle calculated the MTU settlement consistent with the proposed approach

- Brattle used 2032 modeled wheeling revenues in the BAU Case as a proxy for future lost transmission revenue that goes into the settlement calculation
- This differs from some of the original EDAM cases which used historic wheeling revenues provided by the clients as the basis for the EDAM TRR settlement